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SHASTA
Subsurface Hydrogen Assessment, Storage, and Technology Acceleration

Field Test Plan for Underground Hydrogen Storage Demonstration in a Porous Reservoir

SHASTA: Subsurface Hydrogen Assessment, Storage, and Technology Acceleration Project

June 2024

Prepared for the U.S. Department of Energy, Office of Fossil Energy and Carbon Management by:

Sandia National Laboratories: Franek Hasiuk, Mathew Ingraham, Don Conley

U.S. DEPARTMENT OF ENERGY | Fossil Energy and Carbon Management

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Executive Summary

Climate and sea level change is causing numerous challenges across the globe to human societies and the cultural and infrastructure investments they have made over hundreds of years based on previous modalities in climate and sea level. Decarbonizing our global economy is therefore essential to stopping additional emissions of CO_2 to the atmosphere. One proposed decarbonization technology that has been advanced as a replacement for the "hydrocarbon economy" that exists today is the "hydrogen economy." In the hydrogen economy, hydrogen is both an energy carrier and an industrial feedstock that can replace hydrocarbons' traditional roles in these systems. While most hydrogen is produced from conventional, fossil-based feedstocks, hydrogen comes with the added benefits of being able to be made from water and electricity providing a promising way to store renewable energy from wind and solar developments.

The promise of a fully deployed hydrogen economy requires research and development activities that can answer fundamental scientific, engineering, and safety questions about hydrogen systems. More plainly, energy storage is needed, where UHS can play a large role in advancing the hydrogen economy is a demonstration injection of hydrogen into a subsurface porous media reservoir along with associated monitoring and scientific studies.

Analysis performed in this study and interviews held with a variety of stakeholders suggest the following parameters (bolded below) for a field-scale demonstration injection of hydrogen into a subsurface porous media reservoir. Through these assessments, the most common geological type of reservoir in the U.S. fleet of gas storage reservoirs is a ***Paleozoic sandstone***. Performing a test in such a reservoir would be the most broadly applicable. It would be most economically and operationally simple to use methane as base gas, so a reservoir that already had some methane saturation would be ideal (i.e., a ***depleted natural gas field***). Running the demonstration at a ***newer facility*** will result in reduced risk of the facility having unknown corrosion in its system that may perform poorly during the demonstration. Performing the ***test in a low-sulfur reservoir*** (either as pyrite or dissolved sulfate) would minimize the chances for H_2S production and the need for treating the extracted gas. ***A test cycle of ~2 years*** would allow a full injection/production cycle to be captured along with some "wiggle room" for when the project starts. Choose a ***reservoir with a low-moderate pressure*** (e.g., 1200 psi) to save on compression costs and reduce the risk of caprock or wellbore integrity issues. Test at a high deliverability rate (minimum of 2 BCF/day minimum, but preferably 20-100) to be representative of the rates at which current natural gas storage reservoir operate. ***Inject a high total volume*** (~2 BCF of hydrogen over the storage cycle or approximately 6 months at a rate of ~10MCF/d). This would allow it to be of similar magnitude and rate to current natural gas storage reservoir operations resulting in a test that is most relevant to the largest, and most analogous commercial gas storage industry in the US.

The project will follow industry best practices for underground natural gas storage (e.g., American petroleum Institute Recommended Practices 1171) for subsurface gas storage, modifying those practices where appropriate to account for the unique properties of hydrogen gas. Major scientific research tasks for **the reservoir-caprock system** are: following the geometry of the hydrogen bubble, keeping account of hydrogen during storage operations, and characterizing how hydrogen interacts with reservoir fluids and geological materials (e.g., reservoir rock, caprock). Major scientific research tasks for **the well system** are: assessing the sealability of gas-tight connections, identifying the appropriate cement for well construction, monitoring the performance of well materials, detecting leaks in the subsurface and in surface equipment, performing a cost-benefit analysis of subsurface safety valves, comparing casing inspection tools. **Public engagement and outreach** will include assessing well surveying methods and recordkeeping as well as performing an environmental justice analysis for communities around the proposed demonstration. In addition, the project will explore the utility of a **field laboratory** where materials and methods can be tested in a more real-world setting before commercial deployment.

Acknowledgments

This work was supported by the U.S. Department of Energy, Office of Fossil Energy and Carbon Management (FECM) through the Subsurface Hydrogen Assessment, Storage, and Technology Acceleration (SHASTA) project.

Acronyms and Abbreviations

AOR	Area of review
API	American Petroleum Institute
API 1171	American Petroleum Institute's Recommended Practice 1171 *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs*, 2nd edition, 2023.
Bcf	billion cubic feet
CAPEX	capital expenditures
CCS	CO_2 capture and storage
CF	capacity factor
CCUS	CO_2 capture, use, and storage
DRI	direct reduction of iron
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FERC	U.S. Federal Energy Regulatory Commission.
IOGCC	Interstate Oil and Gas Compact Commission
Mcf	thousand cubic feet
MMcf	million cubic feet
NG	natural gas
O&M	operations and maintenance
OPEX	operations and maintenance expenditures
PHMSA	U.S. Pipeline Hazardous Materials Safety Administration
UGS	underground natural gas storage
UHS	underground hydrogen storage
UIC	underground injection control (i.e., wastewater disposal wells)

Definitions

These definitions are modified from *Kansas Regulations 82-3-1000. Definitions:Underground Porosity Gas Storage Facilities*.

Caprock: a layer of relatively impermeable rock that lies *above* a reservoir layer and provides both capillary and mechanical seal against upward or later flow of buoyant fluids out of the reservoir rock. Examples of caprocks can be shales or evaporites.

Baserock: a layer of relatively impermeable rock that lies *below* a reservoir layer that may provide seal against upward or lateral flow of buoyant fluids out of the reservoir rock. Examples of baserocks can be shales or evaporites.

Reservoir Rock: a layer of relatively permeable and porous rock. Examples of reservoir rocks can be porous sandstones or carbonates.

Cushion gas: the volume of gas required as permanent storage inventory to maintain adequate reservoir pressure for meeting minimum gas deliverability demands throughout the withdrawal season or cycle.

Fracture gradient or **frac gradient**: the pressure gradient, measured in pounds per square inch per foot, that will cause that formation to physically fracture if applied to a subsurface formation.

Fresh water: Water containing not more than 1,000 milligrams of total dissolved solids per liter.

Gas storage field: an underground reservoir and superjacent sealing rock together in a trapping geometry such that an economic amount of gas can be stored within the geometry.

Gas storage injection well: a well used to inject gas stored into an underground reservoir.

Gas storage monitoring well: a well either completed or recompleted for the purpose of monitoring subsurface phenomena, including the presence of gas, pressure fluctuations, fluid levels and flow, temperature, etc.

Gas storage porosity reservoir: a porous stratum of the Earth that is separated from any other similar porous stratum by an impermeable stratum and is capable of being used for underground storage of gas.

Gas storage well: any gas storage injection or withdrawal well, gas storage withdrawal well, or gas storage observation well completed or recompleted as part of a *gas storage facility*.

Gas storage withdrawal well: a well used for the withdrawal of gas stored in an underground reservoir.

Leak detector: a device capable of detecting by chemical or physical means the presence or the escape of vapor.

Qualified engineer: an engineer that is licensed, authorized, and/or qualified to practice engineering in the state of the *gas storage facility*.

Qualified geologist: a geologist that is licensed, authorized, and/or qualified to practice geology in the state of the *gas storage facility*.

Packer: an expanding mechanical device used in a well to seal off certain sections of the well when cementing, testing, or isolating the well from the completed interval.

Underground porosity gas storage: the storage of gas in underground porous and permeable geologic stratum that has been converted to gas storage.

Underground porosity gas storage facility and **gas storage facility**: the leased acreage associated with the gas storage field. This term will include the wellbore tubular goods, the wellhead, and any related equipment, including the last positive shutoff valve attached to the flowline.

Working gas: the portion of the gas storage volume that can be removed from a *gas storage porosity reservoir* for deliveries and still maintain pressure sufficient to meet design deliverability and safety metrics.

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1.0 Introduction

Climate and sea level change is causing numerous challenges across the globe to human societies and the cultural and infrastructure investments they have made over hundreds of years based on previous modalities in climate and sea level. Paleoclimate data have shown that the climate and sea level change we are experiencing is anomalous within recent geological history. Time series of the carbon isotopic composition of atmospheric CO_2 has shown that its increase has been driven by anthropogenic emissions of carbon dioxide (CO_2) from burning fossil fuels. Decarbonizing our global human economy is therefore essential to stopping additional emissions of CO_2 and other greenhouse gasses to the atmosphere.

One proposed decarbonization technology that has been advanced as a replacement for the "hydrocarbon economy" that exists today is the "hydrogen economy". In the hydrogen economy, hydrogen is both an energy medium and an industrial feedstock that can replace hydrocarbons' traditional roles in these systems. Hydrogen comes with the added benefits of being able to be made from water and electricity providing a promising way to store renewable energy from wind and solar developments. The byproduct of its combustion is only water. Up to 5-10% by volume, hydrogen can also be transported in today's natural gas pipeline network and burned in natural gas appliances and industrial equipment without modification yielding an important bridge from our current hydrocarbon economy to the future hydrogen economy.

The promise of a fully deployed hydrogen economy requires research and development activities that can answer fundamental scientific, engineering, and safety questions about hydrogen systems. One of the significant questions surrounding the hydrogen economy is: can hydrogen be stored underground like we do with natural gas today? The modern US natural gas distribution system is anchored by 378 underground storage facilities in porous media (n=340) or caverns (n=38) that provide resiliency to the system by providing large volume energy storage closer to customers. Today, a handful of underground sites globally have proved the technical and commercial viability of storing hydrogen in engineered salt caverns (three in Texas, USA; one in the UK), yet salt cavern storage of natural gas represents only 10% of the number of storage sites in the US. For hydrogen to fully penetrate the energy storage market, it remains to be demonstrated that hydrogen can be stored in porous media, which represents the other 90% of the current storage fleet.

Therefore, one significant need for advancing the hydrogen economy is demonstrating underground hydrogen storage (UHS) in a subsurface porous media reservoir along with associated monitoring and scientific studies. The goal of this document is to define the scientific basis a UHS demonstration (the remainder of this chapter) as well as a work program to execute that research and development plan via a UHS demonstration (Chapters 2-11).

The first step in writing this document was to talk to experts in the field of underground gas storage. These included: midstream pipeline operators of natural gas storage fields, regulators, academic and national laboratory researchers, and staff at geological surveys. From these conversations, numerous key questions (Subchapter 1.1) arose that would be best answered with a UHS demonstration. In addition, these conversations yielded numerous subsurface engineering parameters (Subchapter 1.2) for determining the scale of a UHS demonstration (e.g., total gas volume stored, producibility rate, pressure). They are not an exhaustive list of all R&D questions that exist surrounding this gas storage type, nor are they a perfect list of what a potential demonstration project must do. Rather, they provide some fundamental research questions that a demonstration project might include.

1.1 Research and Development Plan

Aside from the standard geological and engineering questions that arise during any gas storage exploratory program, a UHS demonstration in a porous media reservoir provides the opportunity to test numerous hypotheses through the deployment of novel instrumentation and the collection of new data in association with this novel event. This subchapter documents scientific questions, their associated hypotheses and the methods by which those hypotheses would be tested during the demonstration. These research questions and their associated hypotheses are integrated into the task descriptions below.

Research Question 1: What is the geometry of the injected hydrogen bubble? Reservoir modelling studies have suggested that injected hydrogen may not behave in the same way as other injected gases like methane (CH_4) or carbon dioxide (CO_2). This could affect how Subsurface Engineers design and construct wells in a greenfield hydrogen storage development as well as affect the ability to convert legacy facilities.

- ***Hypothesis 1*** that could be tested could be that "the hydrogen bubble that forms during storage will follow the geometry suggested by simulation studies." This could be tested by collecting reservoir fluid and gas samples from monitoring wells to identify the extent to which hydrogen has reach certain parts of the field. In addition, down-hole temperature sensors could identify the temperature disturbance caused by the injected hydrogen in real-time without needing to bring samples to the surface or run chemical tests.

- ***See Subtask 11.2 for hypothesis test***

Research Question 2: How do we keep account of hydrogen during storage operations? Injected hydrogen will interact with reservoir fluids, microbial communities, and geological materials and may change its mass as well as its elemental and isotopic composition. This could be problematic during production season because the gas coming out of the reservoir may not meet the volume or storage requirements of the pipeline customers and thus affect the value a storage operator could charge for their storage services.

- ***Hypothesis 2*** that could be tested could be that "the elemental and isotopic chemistry of reservoir water can accurately predict the quantity and composition of hydrogen during production." This could be tested by collecting sampling reservoir water from monitoring wells and analyzing its chemical, biological, and isotopic composition. This would allow storage operations to adequately prepare for the production season by having enough materials on hand to treat produced hydrogen before introducing it into the pipeline.

- ***See Subtask 11.3 for hypothesis test***

Research Question 3: How does injected hydrogen interact with reservoir fluids? In current natural gas storage operations, when pipeline-grade natural gas (99.9% methane) is injected into an underground porous media reservoir it picks up a variety of impurities while in the underground reservoir, chief among these is water. Triethylene glycol is used currently to dehydrate the gas upon production. Because we have so little data about how hydrogen gas interacts with underground reservoirs, we don't know how much of this connate water would hydrogen absorb.

- ***Hypothesis 3.1*** that could be tested could be "hydrogen will interact with reservoir fluids similarly to natural gas." This could be tested by measuring the composition of injected and produced gas as well as monitoring reservoir water chemistry during the demonstration injection.

- ***See Subtask 11.3 for hypothesis test***

- ***Hypothesis 3.2*** that could be tested would be "produced hydrogen can be dehydrated using triethylene glycol." This could be tested by passing the produced gas mixture through similar process equipment used for dehydrating natural gas.

- ***See Subtask 11.4 for hypothesis test***

Research Question 4: What is the reactivity of clay minerals in the presence of hydrogen? Clay minerals are the most diverse group of minerals in nature due to their complex crystal forms and penchant for adsorbing chemical species. In a reservoir-caprock system, clay minerals will make up a majority of the caprock and their material properties will in large part determine the maximum allowable operating pressure of the reservoir. In addition, clay mineral may exist in the matrix of the reservoir rock where their large surface areas may provide a site for chemical and biochemical reactions.

- ***Hypothesis 4*** that could be tested could be "hydrogen will have negligible effect on seal or reservoir materials." This could be tested by collecting rotary sidewall cores at the completion of the demonstration injection and comparing them to core samples taken during well construction to identify any alteration that was caused by the injected and stored hydrogen.

- ***See Subtask 11.5 for hypothesis test***

Research Question 5: What is the sealability of gas-tight connections? We know that hydrogen can have major effects on certain blends of steel. However, even with steel formulated for exposure to hydrogen, the connections between steel equipment can become the most likely points of failure.

- ***Hypothesis 5.1*** that could be tested could be "fiber optic sensing can be utilized to monitor the connection points between wellbore steel for hydrogen leaks." This could be tested by installing fiber optic sensors during well construction that could monitor for leaks at each join in the well casing.

- ***See Subtask 11.1 for hypothesis test***

- ***Hypothesis 5.2*** that could be tested could be "pipe connection seal materials designed to prevent hydrogen leakage will adequately contain hydrogen gas to facilities piping." This could be tested by testing a variety of pipe sealing materials (e.g., gaskets, glues, or "pipe dopes" of various compositions) and then using leak detectors to measure their ability to prevent leaks during the time span of the test injection.

- ***See Subtask 11.1 for hypothesis test***

Research Question 6: What is the appropriate cement to use in well construction? Wellbore cement is a complex mixture of di- and tri-calc silicate with an extremely basic pore water composition. It is known that the interaction with acid gasses can cause premature deterioration of well bore cement leading to loss of containment of wellbore fluids. Numerous laboratory studies have investigated the effects of hydrogen on cement and concrete materials at the bench-scale. However, because of the rarity of hydrogen operations in wellbores, especially in porous media reservoirs, scant data exists on how hydrogen and cement interact at the wellbore scale over the time scales of traditional gas storage operations.

- ***Hypothesis 6*** that can be tested is that "the blend of cement used in wells at salt cavern facilities storing hydrogen would provide adequate performance at a porous media facility storing

hydrogen." This could be tested by collecting rotary sidewall cores of wellbore cement before and after UHS demonstration to assess any alteration of the cement in the presence of hydrogen. Different cement compositions (e.g., with and without resin additives) could also be use at different depths in the well bore.

- ***See Subtask 10.1.3 for hypothesis test***

- Long-term R&D is needed to develop new and better tools for cement (and casing) inspection. The current preferred tool is ultrasonic inspection logging. However, this tool requires all the production tubing to be removes that the wellbore to be filled with fluid (e.g., brine or drilling mud). The next best tool is based on magnetic flux, but the interpretation of the data is "black box" from the tool vendor, so little is known of the exact physical basis for the measurement. If the ultrasonic tool could be modified to function in a wellbore filled with hydrogen gas, it would improve the ability to identify cement and casing corrosion and allow remedial action to be taken before problematic situations arise.

Research Question 7: How do we monitor for underground leaks? It is likely that small leaks will occur in the subsurface before they grow to the size that they can be detected at the surface. Novel technologies either installed during well construction or deployed during routine maintenance may be able to detect such leaks before they grow to problematic scale. Current technologies such as fiber optics are expensive, their electronics are fragile compared to the sometimes-harsh field environments, and the resulting stream of data (gigabytes per day) is too much to handle with standard manual data analysis routines.

- ***Hypothesis 7*** that could be tested could be "artificial intelligence and machine learning can be employed to sift through monitoring data to identify significant events and trends in monitoring parameters to identify wellbore leaks." This hypothesis could be tested by having AI/ML routines watch incoming data from the demonstration injection to establish baseline telemetry data that could be used to identify concerning events or trends.

- ***See Subtask 7.6 for hypothesis test***

Research Question 8: How do we monitor for surface leaks? Hydrogen is a greenhouse gas that has a similar potential to methane. Hydrogen that leaks from storage operations would negate some of the benefit from the development of a hydrogen economy to replace our current hydrocarbon economy. Most emission at current natural gas storage fields come from well maintenance and rehabilitation operations.

- ***Hypothesis 8*** that could be tested is that "current chemical hydrogen monitoring devices can detect leaking hydrogen from surface facilities and equipment." This hypothesis could be tested by setting up leak detectors at various distances from major pieces of process equipment (e.g., wellhead, compressor, dehydrator, pipe connections) to identify how close detectors need to be to identify leaks. In addition, local (e.g., infrared) and remote (e.g., satellite) sensing technologies can be tested to determine the extent to which measurement could be made from even further afield which may improve the economics of site monitoring.

- ***See Subtask 7.6 for hypothesis test***

Research Question 9: Would a field laboratory for UHS be useful? In addition to these research questions, it may be beneficial to develop a "lab in the field" for hydrogen storage in porous media where various construction, production, and monitoring technologies and materials could be tested long term in a field environment. Such a facility could consist of a 5-spot well development with one central injector/producer with four monitoring wells located at various standoff distances.

- ***See Subtask 11.6 for hypothesis test***

Ancillary Reports: A UHS demonstration can also be beneficial in testing hypotheses needed to advance the safety of the current natural gas storage fleet. In a report issued by the US Well Integrity Working Group in the wake of the Aliso Canyon Incident (Freifeld et al., 2017), several recommendations were made for additional research and development activities that could increase the safety of natural gas storage wells. These included:

- ***Ancillary Report 1:*** "A quantitative cost-benefit analysis of downhole safety valves is needed to resolve uncertainty in their benefit for the U.S. natural gas storage industry."
  - This analysis could be included during the well design process. To support his project the analysis would need to include hydrogen-rated valves, but including natural-gas rated valves would likely present only a minimal additional burden because those valves are more commonly deployed across industry.
  - ***See Subtask 7.5 for report specifics***
- ***Ancillary Report 2:*** "A systematic study comparing the effectiveness of different casing evaluation tools is needed."
  - Such a study directly dovetails with the research question above "***How do we monitor for underground leaks?***" In addressing the question for hydrogen storage, it is required to review the current tools used during natural gas storage to monitor and evaluate downhole equipment and materials for leaks.
  - ***See Subtask 10.1.3 for report specifics***
- ***Ancillary Report 3:*** "State agencies or other stakeholders should undertake a thorough investigation of wellbore registration, record keeping, and survey practices."
  - As part of the risk analysis implicit in this project as well as effective stakeholder engagement, this project will work with appropriate regulatory bodies to develop a best practices document for improving wellbore registration, record keeping, and survey practices in the jurisdiction in which the demonstration occurs. While most jurisdictions (mostly states) have their own unique formats for wellbore records this best practices will still be beneficial for two ways. First, whatever best practices are identified will probably be applicable to the jurisdiction's entire fleet for oil, gas, gas storage, and underground injection control wells. Second, there will still likely be valuable learnings that are cross-jurisdictional. For example, if new techniques are identified to quickly digitize well logs into LAS-formatted digital well logs.
  - ***See Subtask 3.11 for report specifics***
- ***Ancillary Report 4:*** "Data should be collected that considers proximity to population centers relative to new gas storage field facilities, and new wells in existing gas storage fields.
  - This analysis is also implicit in the risk analysis portion of planning for the UHS demonstration and will follow appropriate regulatory requirements. In addition, an analysis could be performed to map the setbacks that different jurisdictions in the US apply to different types of wells and compare that with what knowledge exists for how

far the effects of general events (e.g., noise, emissions) and catastrophic events (e.g., well control incidents) can spread beyond a well site.

- ***See Subtask 4.4 for report specifics***

In the end, this UHS demonstration may be unsuccessful with the project failing to show safety or feasibility of UHS in a porous media reservoir. While it seems more likely that the demonstration will show that underground hydrogen storage is safe and feasible under certain circumstances, it is important to ensure that even if demonstration is deemed unsuccessful, that learning could still be applied to current natural gas storage operation in porous media reservoirs or current hydrogen storage operations in salt caverns. For that reason, **Project Staff** should contemplate how they we translate new learnings from a demonstration injection to these operations.

1.2 Subsurface Engineering Parameters

Through conversations with numerous subsurface professionals in industry, academia, and government, a series of subsurface engineering properties were identified that would make the results of a demonstration as broadly interesting and applicable as possible.

Use a former depleted natural gas field. While the database does not break out depleted oil reservoirs from depleted gas reservoirs, it would be ideal from a cost and simplicity standpoint to use a depleted natural gas reservoir for the demonstration. It would be most economical and operationally simple to use methane as base gas, so a reservoir that already had some methane saturation would be ideal. Starting with a blend of hydrogen (perhaps 10%) when the injection commences and then increases during the demonstration to 100% while watching the behavior of field equipment and reservoir fluids samples from monitoring wells would provide valuable insight.

Find a newer facility. The biggest concern among operators may be the interaction between hydrogen and legacy materials (e.g., steel, cement, elastomers). Running the demonstration at a newer facility will result in reduced risk of the facility having unknown corrosion in its system that may perform poorly during the demonstration.

Low sulfur content. Dissolved sulfate (SO_4) in reservoir water may react with injected hydrogen especially in the presence of certain microbial communities to produce hazardous hydrogen sulfide (H_2S) that would need additional remediation when stored hydrogen was returned to the surface.

Long test cycle. A testing cycle of at least two years would allow the performance of the demonstration to be monitored over one full injection-production cycle as well as provide the flexibility to start the demonstration as soon as possible and potential do a short injection-production cycle first (e.g., one month in, one month out). This would give operators and regulators the best look at how a hydrogen storage operation would perform in service similar to current natural gas storage facilities.

Lower reservoir pressure. Most natural gas storage reservoirs operate between 200-5000 psi. 1200 psi would be ideal to save on compression costs and still provide representative reservoir performance data. Lower pressure would also reduce the risk of compromising the integrity of caprock or wellbore.

Higher deliverability rate. To provide useful data the test should produce at a minimum of 2 MCF/day minimum, but between 20-100 MCF/day would be more representative of the rates at which current natural gas storage reservoir operate.

Higher storage volume. The demonstration should aim to store 2 BCF of hydrogen over its storage cycle (approximately 6 months at a rate of ~10MCF/d). This would allow it to be of similar magnitude and rate to current natural gas storage reservoir operations resulting in a test that is most relevant to the largest, and most analogous commercial gas storage industry in the US. While this would be the largest test to date globally, it would be implicit in the demonstration that injection rates and ultimate total injection volume would be curtailed should monitoring data suggest concern regarding containment.

Based on the above introduction, the parameters for a useful hydrogen injection demonstration into a porous media reservoir begin to become clear. It is important that these parameters be taken as guidelines rather than strict requirements. Any hydrogen injection demonstration should tailor its goals, procedures, and safety program to its particular mission. Due to the relative novelty of hydrogen injection into porous media reservoirs, it is advisable that projects proceed with an abundance of caution because a demonstration viewed as “unsuccessful” could adversely affect the likelihood of future projects for some time to come.

1.3 Design goals

The overriding goal for the field test is to collect the data necessary for a knowledgeable party (e.g., regulator, industry, researcher) to judge the safety and feasibility of subsurface storage of gaseous hydrogen in a porous media reservoir.

Safety is the foremost concern with any subsurface injection operation. In the case of subsurface storage of hydrogen in porous media, safety can be divided into three aspects: geology, wellbore, and facilities.

- ***Reservoir safety*** is centered around the integrity of the reservoir and seal, the geometry of the trap, and properties of local faulting.

- ***Well safety*** involves the wellbore and the geological formations through which it passes, casing, tubing, cement, completions technologies, and any equipment in the wellbore (e.g., packers, plugs).

- ***Site Security safety*** requires an understanding of the surface equipment including pipes, valves, compressors, process equipment (e.g., for dehydration or desulfurization), weather, site, and security, including cyber security).

Feasibility in the context of the UHS demonstration outlined in this report includes the assessment of whether the demonstration is able to meet key performance metrics while operating safely.

The American Petroleum Institute’s recommended practices for natural gas storage operations (API RP 1171, 2023) provide a useful starting point for designing a successful and safe hydrogen test injection. Their guidelines were developed by a committee of subject matter experts to document best practices when assessing the prospectivity of a new site for natural gas storage (greenfield development), the expansion of an existing natural gas storage site, or the conversion of an existing gas or oil field for natural gas storage (brownfield development). These modes will largely mirror what can be expected for the development of UHS in porous media reservoirs.

The fundamental workflow for assessing a site’s potential for natural gas storage include risk analysis, well & reservoir design, safety & operational planning, an injection demonstration, and documentation (API RP 1171, 2023). These steps can be used to develop a workflow for a hydrogen injection demonstration (Figure 1).

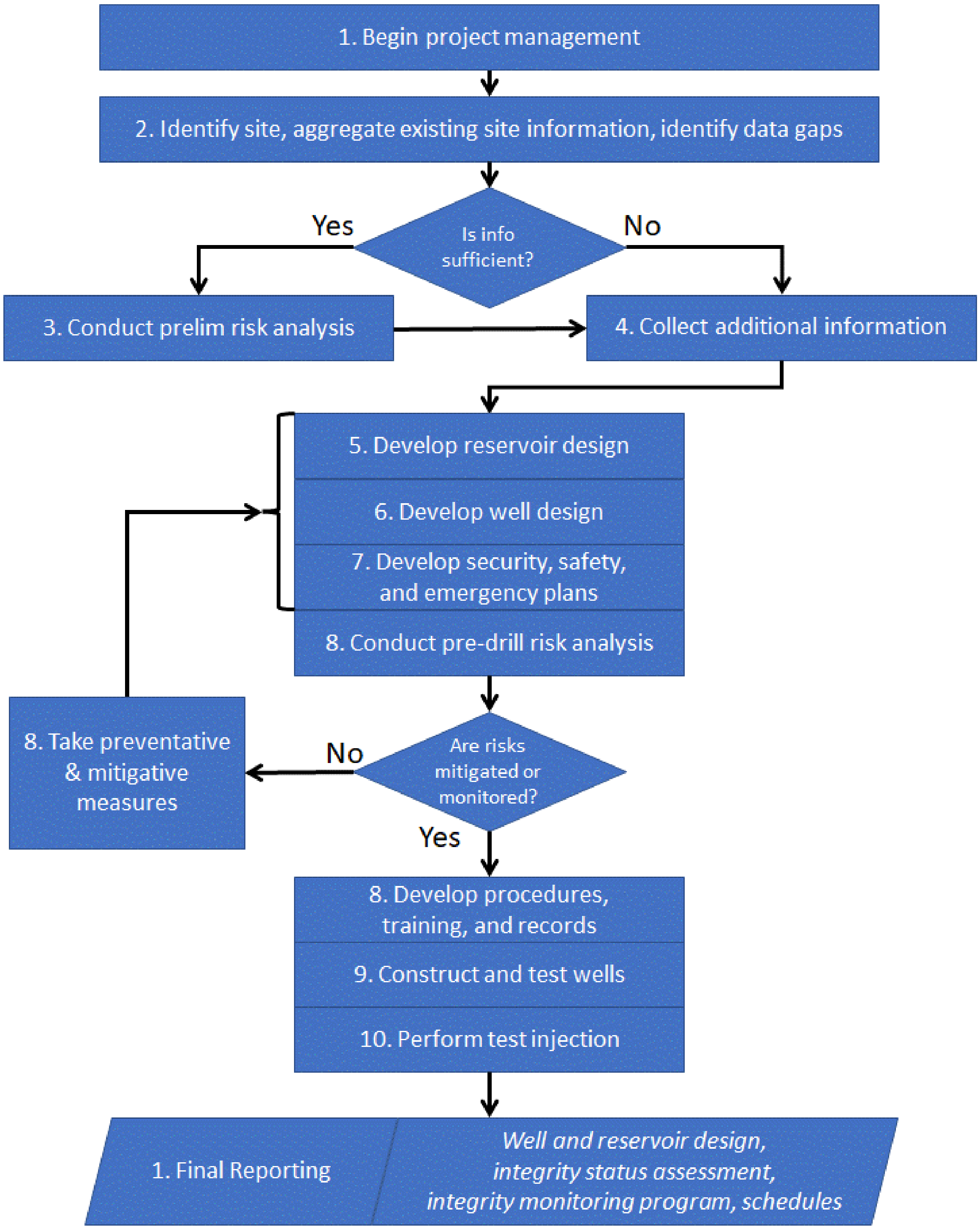

Figure 1: Workflow for test injection base on API Recommended Practices for Gas Storage (API 1171, 2023). Numbers correlate with task numbers.

This 10-task workflow forms the basis for the structure of this report and will be followed by a Research and Development Plan outlining specific technologies that can be incorporated into the field demonstration.

The premise for writing this report is that a test site has been identified through other decision-making processes, such as through criteria outlined in this report's introduction. This report documents the steps necessary to take that through a test injection of hydrogen into a subsurface porous media reservoir.

2.0 Project Management (Task 1)

This section provides a generic Project Management Plan for running a underground hydrogen storage demonstration project that includes a task list, project schedule, deliverables, roles and responsibilities of personnel, and data management plan, and reporting.

2.1 Demonstration core values

The core values for demonstrating underground hydrogen storage will be **safety**, **integrity**, and **equity**. The core value of ***safety*** will be evident in the culture that permeates the activity from project planning thought execution and into after-action reviews. Every participant in the project will be empowered to stop work if unsafe conditions are observed or forecasted. Stakeholder input regarding safety will be solicited, reviewed, and acted upon where appropriate. The core value of ***integrity*** will be evident when participants in this activity regularly and accurately document uncertainties and risks inherent in the activity as well as hold substantive discussions on uncertainty analysis/reduction and risk mitigation. The core value of ***equity*** will be evident when activity participants recognize and characterize biases that may be affecting behaviors, analyses, judgements, or reporting. It will also be evident when participants refrain from broad generalizations and vague speech about project safety, performance, or effectiveness.

2.2 Task List

1. **Project Management**: A Project Management Plan for executing the demonstration injection.
2. **Site Description**: Gathering existing data, building preliminary geological models, performing preliminary engineering simulations, and identifying data gaps.
3. **Preliminary Risk Analysis**: Preliminary hazard identification and analysis as well as development of risk minimization/mitigation plans.
4. **Additional Data Collection**: Collecting additional data identified in Site Description or Preliminary Risk Analysis tasks.
5. **Reservoir Design**: Reservoir engineering to meet demonstration goals.
6. **Well Design**: Well engineering to meet demonstration goals.
7. **Pre-Drill Risk Analysis**: Final pre-drill risk analysis incorporating information from Additional Data Collection as well as Reservoir and Well Design tasks.
8. **Site Security Planning**: Develop physical and cybersecurity plan for project activites.
9. **Well Construction and Testing**: Construction and testing of project wells including laboratory analytical work.
10. **Hydrogen Storage Demonstration**: Injection and withdrawal of hydrogen from underground storage reservoir and post-storage activities.

2.3 Schedule

A Gantt chart (Figure 2) provides preliminary estimates on when project tasks will occur over the length of the project.

	Task	Year 1				Year 2				Year 3				Year 4			
		1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
1	Management & Reporting	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
	Quarterly Reporting	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
	Annual Reporting				X				X				X				X

	DOE Project Review Meeting		X				X				X			X			
2	Site Description	X	X	X											X	X	
3	Prelim Risk Analysis	X	X	X													
4	Data Collection	X	X	X	X												
5	Reservoir Design		X	X	X	X											
6	Well Design		X	X	X	X											
7	Risk Analysis				X	X		X		X		X		X			
8	Site Security					X	X										
9	Well Construction & Testing					X	X	X		X		X		X			
10	Hydrogen Test Injection						X	X	X	X	X	X	X	X			

Figure 2. Gantt Chart showing expected duration of demonstration tasks

2.4 Deliverables

Table 1: Table of deliverable reports for a UHS demonstration.

Task	Deliverable	Responsible Party	Due Date
1. Project Management			
	Project Management Plan	Demonstration Lead	Y1Q1
	Quarterly Reports	Project Manager	Quarterly
	Annual Reports	Project Manager	Q4
	Final Project Report	Demonstration Lead	Y4Q4
2. Site Description			
	Preliminary Pore Pressure Prediction Report	Subsurface Engineer	Y1Q3
	Preliminary Shallow Hazards Analysis Report	Subsurface Geologist	Y1Q3
	Preliminary Reservoir Geology Report	Subsurface Geologist	Y1Q3
	Preliminary Static Geological Model	Subsurface Geologist	Y1Q3
	Preliminary Area of Review Report	Demonstration Lead	Y1Q3
	Preliminary Reservoir Design Report	Subsurface Engineer	Y1Q3
	Preliminary Well Design Report	Subsurface Engineer	Y1Q3
	Data Gap Analysis Report	Demonstration Lead	Y1Q3
	Additional Data Collection Plan (if necessary)	Project Manager	Y1Q3
	Property Rights Report	Comm Manager	Y1Q3
3. Preliminary Risk Analysis			
	Preliminary Risk Management Plan	Demonstration Lead	Y1Q3
4. Additional Data Collection			
	Data Reports	Relevant Project Staff	Y1Q4
5. Reservoir Design			
	Pre-Drill Reservoir Geology Report	Subsurface Geologist	Y2Q1
	Pre-Drill Static Geological Model	Subsurface Geologist	Y2Q1
	Pre-Drill Reservoir Design Report	Subsurface Engineer	Y2Q1
	Reservoir Connectivity Analysis Report	Subsurface Geologist	Y2Q1
	Reservoir Pressure Analysis Report	Subsurface Engineer	Y2Q1
	Geological Penetration Analysis Report	Subsurface Engineer	Y2Q1
	Environmental Impact Analysis Report	Environmental Scientist	Y2Q1

6. Well Design		
Pre-Drill Well Design Report(s)	Subsurface Engineer	Y2Q1
7. Pre-Drill Risk Analysis		
Pre-Drill Risk Management Plan	Demonstration Lead	Y2Q1
8. Site Security Planning		
Site Security Plan	Demonstration Lead	Y2Q2
9. Well Construction and Testing		
Well Construction Report(s)	Demonstration Lead	Y2Q2
Data Reports	Relevant Project Staff	Y2Q2
10. Hydrogen Injection Demonstration		
Data Reports	Relevant Project Staff	Y4Q4
Updated versions of any previous reports (as necessary)	Relevant Project Staff	Y4Q4

2.5 Roles and Responsibilities

The roles of test personnel will be held the same throughout the duration of the demonstration as much as possible to maintain continuity and promote safety. All personnel are empowered to stop work if they believe safety is being compromised.

Any field demonstration will require numerous people to work closely and effectively to execute a project plan that will likely have aspects that have never been attempted before. That novelty coupled with the significant nature of potential negative consequences require close attention to the roles, responsibilities, and communication among the **Project Participants**, which is defined as all people who participate in the project regardless of their employer, title, rank or whether they are receiving funding from the project. All project participants are empowered to report and stop unsafe work practices. This section describes various roles and groups of people who would participate in a field demonstration.

The project management team (i.e., **Demonstration Lead**, **Project Manager**, **Communications Manager,** and **Data Manager**) will follow best practices for scientific project management such as found in the *Collaboration Team Science: Field Guide* (Bennet et al., 2018) published by the National Cancer Institute.

2.5.1 Project institutions

Four main categories of institutions will participate in the Project.

- ***Funding Agency.*** The institution providing the funding for the Project.
- ***Prime Institution.*** The institution to which the funding award was made to execute the project.
- ***Sub-Award Institution(s).*** Other institutions to whom funding from the Funding Agency will flow through the Prime Institution. This can include universities, federally funded research and development centers (e.g., US national laboratories), or a company/Facility Lead who may be coordinating field activities.

- ***Facility Lead(s)***. The institutions (e.g., companies) on whose sites the Project field activities will occur.

- ***Vendor(s)***. The institutions who will perform work for the Project and are typically not paid by sub-award.

    - Drilling Contractor

    - Core Analysis Vendor

2.5.2 Project roles and responsibilities

- ***Project Participants.*** All people who participate in the Project regardless of their employer, title, rank, or whether they receive funding from the project. All project participants are subject to the project's Code of Conduct and are responsible for upholding its Core Values.

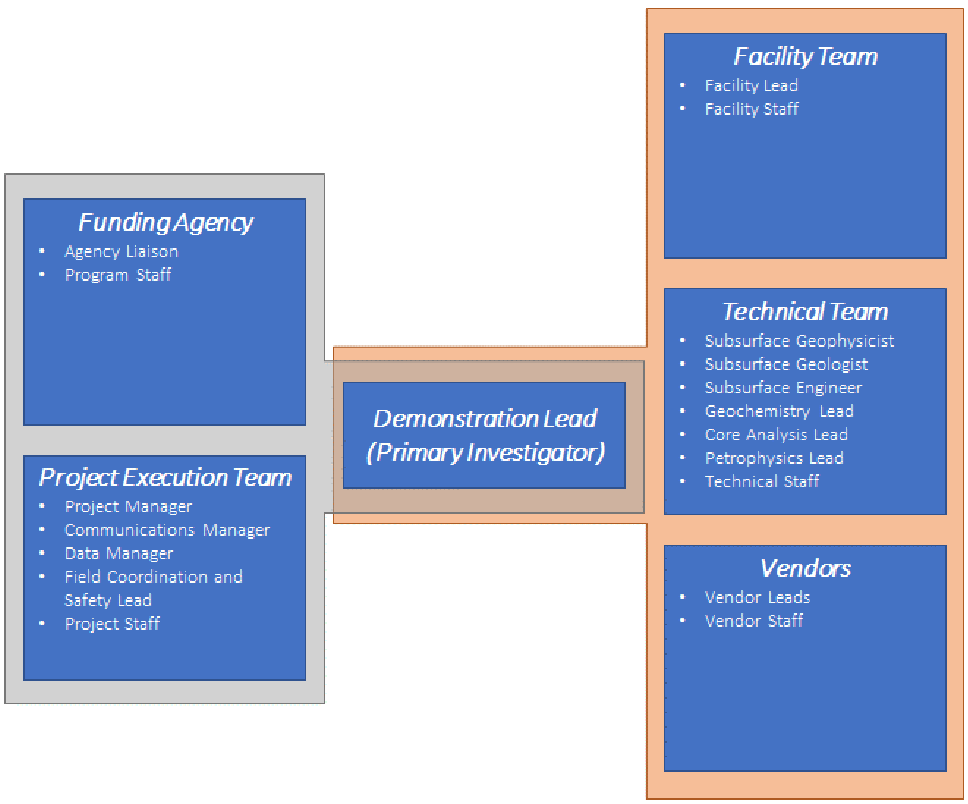

Figure 3: Project organizational chart.

- ***Funding Agency Liaison.*** This person represents the funding agency (e.g., DOE program manager if funded by the DOE), but could also be a representative of upper management at a private company funding the project. They perform oversight of project management and financial integrity.

- ***Demonstration Lead/Primary Investigator.*** This person is responsible for the safe execution of the Project to meet Project objectives. This person will have a scientific background and experience managing projects of this scale.

  - It is the first responsibility of the Demonstration Lead to model a positive Culture of Health and Safety as well as ensure this is promulgated across every aspect of the Project. This is to ensure the physical, mental, and emotional safety of the Project participants as well as the safety of the environment and public.
  - It is a secondary responsibility of the Demonstration Lead to ensure the financial integrity of the Project.
  - It is a secondary responsibility of the Demonstration Lead to ensure the project reaches its objectives or develops suitable alternate objectives should circumstances dictate alterations to the Project.
  - It is a secondary responsibility of the Demonstration Lead to ensure the scientific integrity of the Project and that 1) all findings are reported in a timely manner consistent with the requirements of the Funding Agency and any proprietary considerations of the Facility Lead and 2) all authorship credits are appropriately recognized.

- ***Project Manager.*** This person is responsible for the day-to-day operations of the Project including:
  - Routine communications among the **Project Participants**, including the **Funding Agency Liaison**
  - Business, financial, and human resources management including coordination between funding agency, home organization, and sub-awards
  - Ensuring that all field activities are coordinated with required personnel and the host facility.
  - Ensuring that all health and safety documentation is accurate, complete, and up to date.
  - Verify that all personnel are adequately trained for their activity level work and/or observation roles. They are also responsible for all communications upward from the field team (e.g., lab management, DOE/FECM, Operator leadership, etc.).
  - Submitting reports

- ***Communications Manager.*** This person is responsible for the communications, data management, and public engagement activities of the Project including:
  - Assembling quarterly, annual, and final reports
  - Scheduling regular “all hands” virtual Project meetings
  - Planning outreach events and project in-person meetings
  - Ensuring attendance at virtual and in-person meetings required by the Funding Agency
  - Tracking scholarly output, news stories, and other forms of communication about Project Activities or produced with Project funding

- ***Data Manager.*** Project staff member responsible for project data management and coordination
  - Managing data including raw, processed, interpreted data with project funding including shared cloud storage as well as meeting final requirement for data publishing/storage as enumerated by the Funding Agency.
  - Assembling and managing geological/geographical information systems databases for project work
  - Coordinating scanning and digitizing of legacy data as well as performing quality control/ quality assurance on new and legacy data
- ***Field Coordination and Safety Lead.*** Project staff member is responsible for coordinating field activities.
- ***Subsurface Geophysicist.*** Project staff member who oversees and coordinates geophysical studies including seismic survey design and interpretation, subsurface mapping, and building static geological models. This person would typically have a background in exploration geophysics and geology.
- ***Subsurface Geologist.*** Project staff member who oversees and coordinates geological studies such subsurface mapping, stratigraphic studies, facies interpretation, core description, and building static geological models. This person would typically have a background in geology and/or petrophysics.
- ***Subsurface Engineer.*** Project staff member who oversees and coordinates Subsurface Engineering activities including dynamic reservoir simulation, history matching, well design, drilling operations, and well testing. This person would typically have a background in Subsurface Engineering.
- ***Geochemistry Lead.*** Project staff member who oversees and coordinates planning, execution, and interpretation of data from drilling fluid makeup water, drilling liquids/gasses, drilling fluid tracers, and formation liquids/gasses. This person would typically have a background in (bio, geo)chemistry or petrophysics.
- ***Core Analysis Lead.*** Project staff member who oversees and coordinates planning, execution, analysis and interpretation of core and cuttings data. This person would typically have a background in geology and/or petrophysics.
- ***Petrophysics Lead.*** Project staff member who oversees and coordinates planning, execution, and interpretation of petrophysical well log data. This person would typically have a background in geology and/or petrophysics.
- ***Environmental Scientist.*** Project staff member who oversees and coordinates environmental monitoring and characterization.
- ***Project Staff.*** These are people performing non-scientific project management and execution tasks associated with the project.
- ***Technical Staff.*** These are scientific and engineering researchers who may obtain samples, execute analyses, interpret data, or perform other scientific tasks associated with the project. They

may be professors, researchers, students, lab technicians. They generally have a responsibility to produce scientific reports from the access to Project data or resources that they receive.

- ***Facility Lead.*** Facility staff member in charge of coordinating project activities with the **Demonstration Lead**, the **Project Manager,** and potentially **Vendors**. This person also manages all **Facility Staff** engaged in the Project.

- ***Facility Staff.*** These are staff of the **Facility Lead** who may perform activities associated with the project (e.g., field operations, remote monitoring, administrative tasks).

- ***Vendor Lead.*** Vendor staff member in charge of coordinating project activities with the **Demonstration Lead**, the **Project Manager,** and potentially the **Facility Lead**. This person also manages or coordinates all **Vendor Staff** engaged in the Project.

- ***Vendor Staff.*** These are staff of the **Vendor** who may perform activities associated with the project (e.g., field operations, lab analysis, administrative tasks).

2.6 Work Authorizations

The Project will acquire all appropriate local, state, tribal, and federal permits for the proposed activities.

2.7 External Coordination and Public Engagement Plan

Like many activities that involve the subsurface, there is a tapestry of regulatory bodies that permit, monitor, and tax subsurface gas storage operations. All of these organizations would be stakeholders of a DOE-sponsored demonstration project.

- Individual **state regulatory bodies** (e.g., Kansas Corporation Commission, Texas Railroad Commission) regulate gas storage operations pursuant to state statutes. These bodies likely have the most comprehensive operational knowledge of gas storage operations and should serve as the first point of regulatory contact when planning a hydrogen injection demonstration. The most rigorous gas storage regulations likely exist in California and Kansas due to catastrophic releases from gas storage facilities in those two states.
- Above ground, safety is regulated by **Pipeline Hazardous Materials Safety Administration (PHMSA)**, US Department of Transportation, which is responsible for regulating the transportation of hazardous substances—like natural gas and hydrogen—via pipeline and ensure the security of that infrastructure.
- The **Federal Energy Regulatory Commission (FERC)**, an independent agency within the US Department of Energy that regulates interstate transmission of electricity, natural gas, and oil, regulates the environmental and marketing aspects of subsurface natural gas storage. Though FERC only requires filings when actions are being taken (like expanding or changing operations).
- The **Interstate Oil and Gas Compact Commission (IOGCC)** is a multi-state government agency formed in 1935 to promote the conservation and efficient recovery of oil and natural gas resources within the US. It serves as a forum of collaboration and cooperation among its member states, the major oil and gas producing states in the US, in identifying, documenting, and promulgating best practices for regulation.

- The **American Petroleum Institute (API)** is a trade association representing the US oil and gas industry. It publishes specifications and recommended practices regarding gas storage operations, such as Recommended Practice 1171 (2023) "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs", which provides general procedures for gas storage that were used in the design of the hydrogen injection demonstration detailed in this report.
- Finally, the US **Environmental Protection Agency (EPA)** is charged with protecting groundwater under the Clean Water Act and as such maintains a vigorous Underground Injection Control program regulating the subsurface injection of fluids other than gas storage unless states have been granted primacy overt that enforcement.

2.8 Data management

The Project will follow the FAIR principles (findable, accessible, interoperable, reusable, cf. Wilkinson et al., 2016 and Tornow et al., 2019) for making as much data as possible available to the public upon completion of the project and allowing for a reasonable period of embargo for Project Staff to publish the findings of their studies. A Data Management Plan will guide the preservation and dissemination of data and findings generated within the project in accordance with the DOE Policy for Digital Research Data Management (DOE, 2024). The Project will follow any regulations regarding data reporting and dissemination (e.g., submitting well logs to a state digital repository).

To facilitate information sharing among project team members, these data will be stored in Central Data Repository on an online file-sharing platform. The top-level folders will correspond to the top-level project tasks and the first level of subfolders will correspond to project sub-tasks.

- The **Demonstration Lead** will oversee of the Central Data Repository and safeguard non-public or proprietary information.

- The **Project Manager** will manage access and permissions to all levels of the Central Data Repository.

2.9 Report progress and findings

2.9.1 Quarterly, annual, and final reporting

The Project will supply the Funding Agency with quarterly, annual, and final reports in the format specified that will document the operational and financial performance of the Project against benchmarks and milestones as enumerated in the Project Narrative and Project Management Plan.

2.9.2 Presentations

The Project will deliver in-person and virtual presentations on Project design, progress, and deliverables as enumerated in the Project Narrative and Project Management Plan, including a public project kickoff meeting, a more detailed project kickoff meeting for interested DOE personnel, and annual presentation at an in-person DOE project review meeting.

2.9.3 Physical sample disposition

The Project will reposit any physical samples remaining at the end of the project with an appropriate organization (e.g., state geological survey or US Geological Survey) or dispose of them in accordance with local regulations. Necessary and appropriate repositing fees will be included in the budget.

3.0 Site Description (Task 2)

3.1 Determine preliminary area of review

The first step in the planning process for the demonstration injection is to describe the features of the demonstration site including the facility name as well as the lithological description and average depth of the target porous reservoir(s) and caprock(s), trap type, reservoir drive mechanism, and current fluid composition.

With this information, a preliminary area of review (AOR) is determined that will encompass the geographical area around the proposed demonstration site where underground sources of drinking water (USDWs) may be at risk from the injection activity. This preliminary AOR will be refined later in the process by addressing data gaps and performing more detailed geological and engineering analyses of the project site.

3.2 Aggregate existing information

With a preliminary AOR defined, all relevant data within that AOR is aggregated in a geological/geographical information system. These data can include: 2D and 3D seismic data, well logs, core analysis data, well test data.

For each ***water well*** located within the preliminary AOR, important information will be tabulated including: status, location, identification name and number, completion date, surface elevation, total depth, reference elevation (e.g., Kelly bushing elevation), top and bottom depths of the completed interval, casing information, tubing and packer information, cementing information, flow rate. In addition, available water chemistry data will be tabulated including elemental and isotopic composition of major, minor and trace elements as well as elemental and isotopic composition of dissolved gases. Dynamic data detailing pumping rates and hydraulic conductivity of the USDW will also be collected.

For each ***gas storage well*** located within the preliminary AOR, important information will be tabulated including: status, location, identification name and number, completion date, surface elevation, total depth, reference elevation (e.g., Kelly bushing elevation), top and bottom depths of the completed interval, casing information, tubing and packer information, and cementing information. In addition, available water chemistry data will be tabulated including elemental and isotopic composition of major, minor and trace elements as well as elemental and isotopic composition of dissolved gases. Existing gas storage wells will be evaluated to ensure they meet applicable regulations for demonstration of mechanical integrity.

For ***all other petroleum or underground injection wells*** located within the preliminary AOR, important information will be tabulated including: summary of the status, location, identification name and number, completion date, surface elevation, total depth, reference elevation (e.g., Kelly bushing elevation), top and bottom depths of the completed interval, casing information, tubing and packer information, and cementing information.

Any well information (e.g., well logs, well tops, completions) that has not been scanned will be scanned and copies sent to appropriate regulatory bodies. Important well data will be digitized for inclusion in geological modeling, petrophysical analysis, and engineering simulation.

- This subtask will be performed by the **Geotechnician** in association with **Project Staff** and the **Facility Lead**.

- This subtask will deliver geological/geographical information system databases of subsurface information as well as a file structure in the Central Data Repository with other relevant data.

3.3 Pore pressure prediction

Pore pressure prediction is a process undertaken before drilling a well to estimate the pore pressures likely to be encountered during drilling. It is crucial in drilling operations to avoid losing control of the well by either drilling with either too little mud weight (drilling under balanced that can allow reservoir fluids into the wellbore) or too much (overbalanced drilling that can lead to formation damage, lost circulation, and reservoir fluids entering the formation). Because this demonstration is envisioned to occur at an abandoned, mothballed, or compartment of an active gas storage field, pressure data for both the reservoir formation and superjacent formations is likely to be available. Due to the novel nature of the project activities, it is advisable to conduct a pore pressure prediction exercise *ab initio* to incorporate as much current and legacy data as possible to reduce drilling risk.

- This subtask will be performed by the **Subsurface Engineer, Subsurface Geologist,** in association with the **Facility Lead**.

- This subtask will deliver a *Preliminary Pore Pressure Prediction Report*.

3.4 Shallow hazard analysis

Shallow hazards analysis is another pre-drill process meant to reduce risk to drilling operations from shallow hazards encountered during the early phases of drilling. In the context of this project, a shallow hazards analysis may involve assessing the site for the presence of buried utilities, anomalous soil types, voids (such as natural or man-made caves), the presence of lithologies like evaporites that may wash out during drilling.

- This subtask will be performed by the **Subsurface Geologist** in association with the **Facility Lead**.

- This subtask will deliver a *Preliminary Shallow Hazards Analysis Report*.

3.5 Static geological modeling

Geologic and hydrogeologic evaluation of the gas storage porosity reservoir or reservoirs and the surrounding formations. The evaluation will include any available geophysical data and assessments of any regional tectonic activity, regional or local fault zones, and structural or stratigraphic anomalies. The evaluation will focus on the gas storage porosity reservoir(s) and caprock(s). The evaluation will also identify any oil and gas horizons known to be productive in the area of the storage facility and any freshwater-bearing horizons known to be developed in the area of the storage facility. The evaluation will include figures and plan view maps showing the following:

- County-scale maps showing any regional or local faulting
- Depth-structure maps of the top and base of the storage reservoir(s), showing any faulting
- Isopach map showing the thickness of the reservoirs(s)
- Depth-structure maps of the top and base of the caprock(s), showing any faulting
- Isopach map showing the thickness of the caprock(s)
- Identification of all structural spill points or stratigraphic anomalies controlling the isolation of stored gases or associated fluids

- Structural and stratigraphic cross-sections that describe the geologic conditions at the gas storage test facility
- All these should be certified by a licensed engineer or licensed geologist

- This subtask will be performed by the **Subsurface Geologist** in association with the **Petrophysicist**.

- This subtask will deliver a *Preliminary Reservoir Geology Report* and a *Preliminary Static Geological Model* to the **Subsurface Engineer** for simulation.

3.6 Simulate reservoir performance

- Current and maximum storage volume, including values for cushion gas and working gas for the gas storage test facility, calculated using a method acceptable to regulators and certified by a licensed engineer or licensed geologist
- Information showing that the maximum injection rate and pressure utilized at the gas storage test facility will not exceed the fracture gradient and will not initiate fractures through the overlying strata that could enable stored gas or associated formation fluid to enter fresh and usable water strata or cause the injected gas to leak from the gas storage reservoir. Calculated using a method acceptable to regulators and certified by a licensed engineer or licensed geologist.

- This subtask will be performed by the **Subsurface Engineer** in association with the **Project Staff** and the **Facility Lead**.

- This subtask will deliver a *Preliminary Reservoir Design Report* and *Preliminary Well Design Report*.

3.7 Area of review evaluation

Review of the data of public record for wells that penetrate that part of the underground porosity reservoir designated as the gas storage porosity reservoir, and those wells that penetrate the reservoir(s) within one-fourth mile of the boundary of the underground porosity gas storage facility.

- Determination if abandoned wells have been plugged in a manner that prevents the movement of gas or associated fluids out of the gas storage test reservoir.
- From the review of public records, identification of any wells that appear to be unplugged or improperly plugged, and any other unplugged or improperly plugged wells for which local or anecdotal knowledge may exist.

- This subtask will be performed by the **Subsurface Engineer** and **Subsurface Geologist** in association with the **Demonstration Lead** and the **Facility Lead**.

- This subtask will deliver a *Preliminary Area of Review Report*.

3.8 Identify data gaps

Data gap analysis will be performed based on data collected, preliminary analyses, and requirements set by regulatory regimes.

- This subtask will be performed by the **Demonstration Lead** in association with the **Project Staff** and the **Facility Lead**.

- This subtask will deliver a *Data Gap Analysis Report* and if necessary *Additional Data Collection Plan*.

3.9 Decision point: Are existing data sufficient to proceed to Risk Analysis?

  - If data are sufficient, proceed to Risk Analysis (Task 2).

  - If data are insufficient, proceed to Collect Additional Data (Task 3).

3.10 Property rights survey

- Site map showing the boundaries of the gas storage test facility, the location and well number of each gas storage well, including observation wells, cathodic protection boreholes or ground bed systems, the location of all pertinent surface facilities

- Documentation of necessary and sufficient property rights for construction and operation of the gas storage test facility

- All man-made surface structures and activities within one mile outside of the gas storage facility boundary

- **Notice by mail.** Provide notice to adjacent property owners on or before the date the application is filed with regulator by mailing or delivering a copy of the application to the following:

  - The landowner on whose land the well or wells affected by the application is located

  - Each operator or lessee of record within one-half mile of the boundary of the storage facility

  - Each owner of record of the minerals in unleased acreage within one-half mile of the boundary of the gas storage test facility

Notice by publication. The applicant will publish notice of the application in at least two issues of the official county newspaper of each county in which the lands affected by the application are located. In addition, notice of the application will also be published in at least one issue of a larger regional paper newspaper. The applicant will also deliver or publish any notice that the applicant deems necessary to ensure that those persons whose rights may be affected by the application have been sufficiently notified in accordance with applicable due process requirements.

Public Presentation / town hall. Project representatives will hold a public presentation followed by "town hall"-style question-and-answer session.

- This subtask will be performed by the **Communications Manager** in association with the **Geotechnician**.

- This subtask will deliver a *Property Rights Report*.

3.11 Wellbore data quality

In a report issued by the US Well Integrity Working Group in the wake of the Aliso Canyon Incident (Freifeld et al., 2017), it was recommended that "State agencies or other stakeholders should undertake a thorough investigation of wellbore registration, record keeping, and survey practices." The Project will conduct such a review for the AOR and a reasonable distance around it in concert with appropriate regulatory and/or geological survey officials.

- This subtask will be performed by the **Communications Manager** in association with the **Geotechnician**.

- This subtask will deliver *Ancillary Report 3: Wellbore Registration Report*.

4.0 Preliminary Risk Analysis (Task 3)

This task is based on Chapter 8 (Subchapters 8.1-8.4) of the API 1171.

Risk analysis is a multi-disciplinary approach to assess and mitigate risks to human health, ecosystems, and the environmental arising from project activities. It involves the evaluation of potential hazards such as chemical releases, emissions to the atmosphere, waste disposal, and workplace safety concerns associated with project activities. Through comprehensive evaluations potential sources of contamination and occupational health risks are identified and strategies are developed to minimize or eliminate those risks. By implementing measures, such as engineering controls, administrative procedures, and personal protective equipment, the project can mitigate the adverse impacts of operations and ensure compliance with relevant regulations and standards.

Risk analysis is the fundamental process that minimizes and mitigates risks to the environment as well as personal health and safety from surface and subsurface operations at the test site. From this Risk analysis, a set of safe work procedures is developed called the Risk Management Program. The general workflow for Risk analysis is outlined in Figure 4.

4.1 Data collection and integration

The first step in risk analysis is the identification, collection, and integration of public and proprietary information relevant to the planned site. These data can include:

- Raw data (e.g., seismic data, well locations, well logs, stratigraphic tops, core analysis data, drilling and workover records, well performance data, water chemistry data)

- Interpretive data (e.g., maps, reports, geological models, engineering simulation models, scientific literature)

- Cultural data (e.g., property maps, emergency response information, distances to sensitive locations)

Data will be stored in the Central Data Repository.

Data gaps will be identified.

4.2 Hazard identification and analysis

Hazards are potential sources of harm or adverse effects that can pose risks to people, property, the environment, or project assets. Hazards arise from a variety of sources including natural phenomena, technological processes, human activities, and external events. They can manifest in different forms and have various consequences ranging from minor inconveniences to catastrophic disasters. Understanding hazards is crucial for identifying and assessing risks and implementing measures to manage them effectively to reach project goals.

By recognizing and understanding hazards, the project and the people working on it can implement appropriate measures to mitigate risks, enhance resilience, and promote safety/security within the diverse environments where work will occur.

Hazards can be categorized into four broad types:

- ***Natural hazards***: These are events or processes that occur naturally in the environment such as earthquakes, hurricanes, floods, wildfires, volcanic eruptions, landslides, and droughts.

- ***Technological hazards***: Thes hazards arise from human-made systems, process, or technologies such as chemical spills, explosions, structural failures, transportation accidents, and power outages.

- ***Biological hazards***: These hazards involve exposure to biological agents or byproducts such as pathogens, toxins, allergens, or infectious diseases, which can pose a threat to human health and safety.

- ***Physical hazards***: These hazards include factors in the environment that can cause harm or injury such as extreme temperatures, radiation, noise, vibrations, and ergonomic factors.

Rather than use this categorization, API RP 1171 assigns risks to the three major design activities (i.e., wells, reservoir, and site security) to better focus risk management to these three major pre-drill activities. **Project Staff** will begin this sub-task with the list of commonly encountered hazards and threats in API RP 1171 Table 1 (page 37). These are summarized here in Table 2.

Table 2: Potential hazards to a UHS site modified from API RP 1171 (2023).

Review Category	Hazard	Description
Reservoir	Third-party damage	Poor contractor performance on drilling, completions, or workovers
	Subsurface encroachment	Encroachment on facilities by other subsurface activities (e.g., mineral production, waste disposal, water wells)
	Pressure and Volume Limits	Containment not effective at pressures higher than discovery pressure
		Max/min pressure limits exceeded due to operational oversight
	Geologic uncertainty	Uncertainty in lateral reservoir boundary
		Expansion, contraction, or migration of stored gas
		Caprock failure
	Reservoir fluid compatibility issues	Contamination of reservoir by foreign fluids
	Biogeochemical reactions	Natural or introduced microbial communities may interact with injected hydrogen to consume it and/or produce deleterious byproducts (e.g., H_2S)
Wells	Well integrity	Gas containment failure due to construction quality issues
	Design	Gas containment failure due to design quality issues
	Operation and maintenance activities	Extreme weather; seismicity, subsidence, water table movement / permafrost

	Well construction and intervention activities	Gas containment failure due to loss of wellbore control during well construction or maintenance
	Third-party damage	Accidental or intentional damage
	Natural forces	Extreme weather, seismicity, subsidence, water table movement / permafrost
Site Security	Third-party damage	Accidental or intentional damage
	Surface encroachment	Encroachment on facilities by other land use activities (e.g., farming, pipelines, power lines, wind turbine or solar developments)
	Natural forces	Extreme weather, seismicity, subsidence, water table movement / permafrost
	Flammables on wellsite	Fuel combustion may damage a well or surface facilities

4.3 Develop Risk Management Plan

A Risk Management Plan (RMP) is a structured approach that outlines how an organization identifies, assesses, prioritizes, and mitigates risks to achieve its objectives effectively. It serves as a roadmap for managing uncertainties and potential threats that could impact the project's tasks, operations, or strategic goals. The plan typically includes several key components:

1. ***Data Collection:*** Collection and integration of data necessary to accurately assess risk for the project.
2. ***Risk Identification***: This involves systematically identifying potential risks that could arise from internal or external sources. These can include financial risks, operational risks, compliance risks, safety risks, and others.
3. ***Risk Analysis***: Once risks are identified they are assessed in terms of their likelihood of occurrence and potential impact. This assessment helps prioritize risks based on significance to the project's objectives.
4. ***Risk Prevention & Mitigation***: After prioritizing risks, the plan outlines strategies and actions to prevent or mitigate these risks. This can include implementing controls, transferring risk through insurance or contracts, avoiding certain activities, or accepting risk if it falls within acceptable tolerances.
5. ***RMP Documentation***: The RMP is documented and promulgated across the Project and Facility Staff in such a way as all participating in the project are aware of its contents, how to prevent and/or mitigate risks, how to raise concerns, and how to update the RMP.
6. ***Risk Monitoring and Review***: The RMP includes procedures for monitoring risks over time and periodically reviewing the effectiveness of risk mitigation measures based on performance metrics. This allows for adjustments to the plan as new risks emerge or as the project's objectives and operating environment change.

Overall, the RMP provides a systematic framework for proactively addressing uncertainties and minimizing potential negative impacts on the project's performance and objectives. It is an essential tool in ensuring resilience and adaptability in complex operating conditions.

Substantive meetings and communication will occur with proper local, state, and federal regulatory bodies and with jurisdiction over the proposed gas storage test facility as well as local communities.

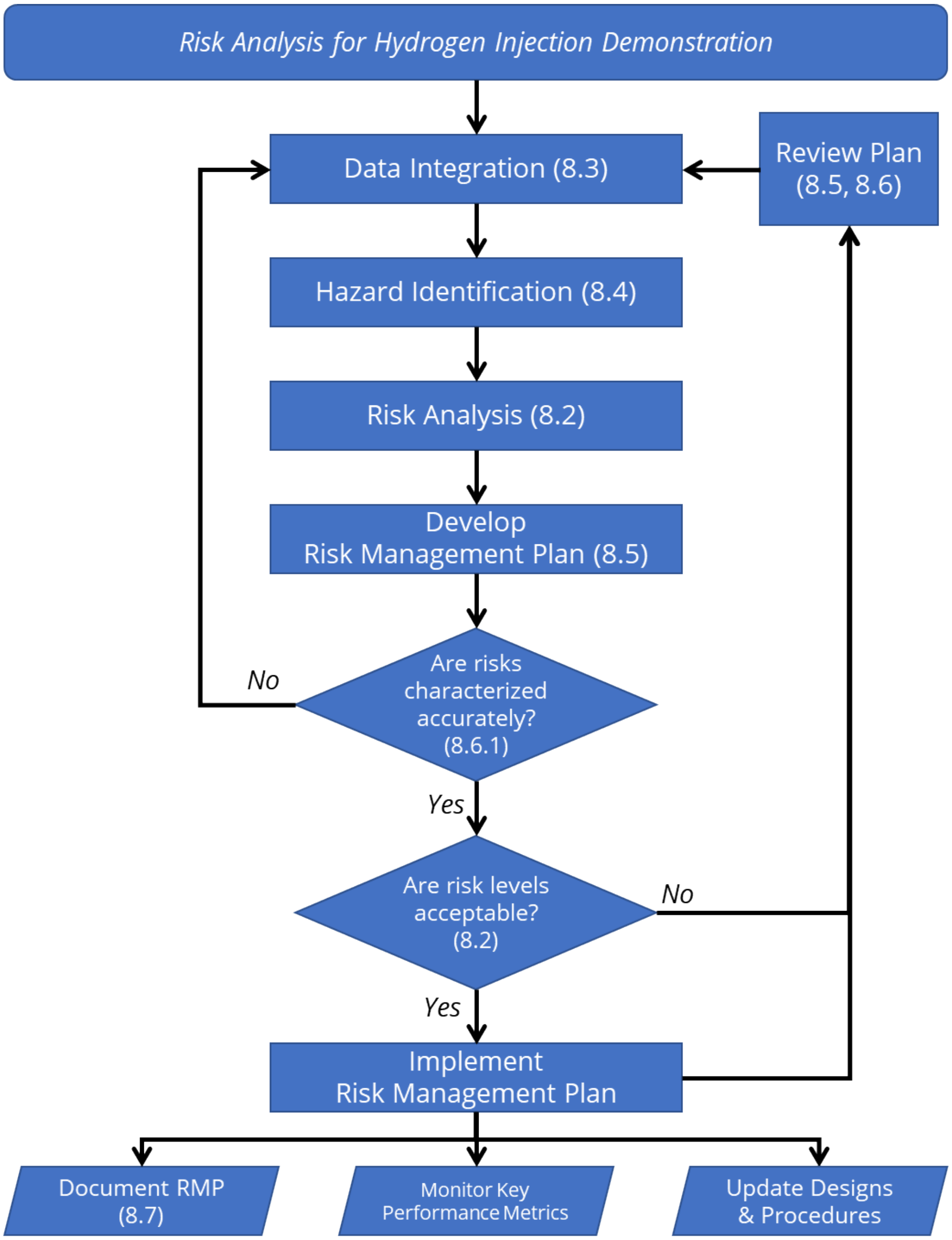

Figure 4: Risk analysis flowchart. Number in parentheses are how risk analysis steps map to specific sections of API 1171 (2023).

- This task will be performed by the **Demonstration Lead** in association with the **Project Staff** and the **Facility Lead**.
- This subtask will deliver a *Preliminary Risk Management Plan*.

4.4 Population Proximity Report

In a report issued by the US Well Integrity Working Group in the wake of the Aliso Canyon Incident (Freifeld et al., 2017), it was recommended that "Data should be collected that considers proximity to population centers relative to new gas storage field facilities, and new wells in existing gas storage fields." Such a report will be written based on project activities following appropriate regulatory requirements. The analysis will map the setbacks that different jurisdictions in the US apply to different types of wells and compare that with what knowledge exists for how far the effects of general events (e.g., noise, emissions) and catastrophic events (e.g., well control incidents) can spread beyond a well site.

- This task will be performed by the **Project manager** in association with **Project Staff** and the **Facility Lead**.

- This subtask will deliver *Ancillary Report 4: Population Proximity Report.*

5.0 Additional Data Collection (Task 4)

This task is based on Chapter 5 (Subchapters 5.2-5.3) of the API 1171.

5.1 Collect Additional Data

It may be required to collect additional information if based on the initial geological characterization, engineering characterization, and risk analysis it is deemed that additional information is required before proceeding with drilling new wells. The data collection activities below are considered of a reduced scale and risk compared to the data collection activities associated with constructing injection or monitoring wells because there is little risk to the surface or subsurface environment from these activities. In many cases the activities listed in this task are carried out by vendors who supply data to the project for analysis. Possible additional information that may need to be gathered:

- **3D Seismic survey**. If a 3D seismic survey is not available over the project site, it is vital that one be collected. This survey will provide key geometric attributes of the storage reservoir and caprock as well as the structural trap and any faults that may affect the integrity of the trap or caprock. After these data are collected and processed, another iteration of geological modeling and reservoir simulation should be undertaken to improve accuracy of reservoir performance prediction. This data collection would be coordinated by the **Subsurface Geophysicist**.

- **Baseline groundwater data**. If the existing USDWs have not been characterized adequately or recently, it is advisable to collect baseline water quality and quantity data for comparison with post-injection data. This data collection would be coordinated by the **Geochemistry Lead**.

- **Core description**. If core descriptions or stratigraphic models used to describe the reservoir or caprock have not been updated in the last 20 years, it is advisable to revisit any cores that exist in repositories. Significant advances in the science of stratigraphy especially with respect to shale (i.e., caprocks) that may improve the prediction reservoir or caprock performance. It is also useful for as many of the project team to personally visit core material from the reservoir and caprock to develop the best understanding of the horizons into which the injection activities will be performed. This data collection would be coordinated by the **Subsurface Geologist**.

- **Core analysis data**. If no or minimal core analysis data (e.g., porosity/permeability, geomechanical data) exist and legacy cores exist in repositories, the collection of additional core analysis data from these legacy cores should be considered. If pre-drill analysis is not possible to time constraints, it should be considered whether additional core analysis data from legacy cores should be included into the core analysis program along with cores from new project wells. This data collection would be coordinated by the **Core Analysis Lead**.

- **Well Integrity Testing.** Risk Analysis or Geological Penetration Analysis may identify certain wells need additional integrity testing (e.g., cement bond logs, mechanical integrity testing) based on the test parameters of the injection demonstration. This data collection would be coordinated by the **Subsurface Engineer**.

- These tasks will be performed by the **indicated personnel** in association with the **roject manager and Data Manager** and the **Facility Lead**.

- Each separate data collection activity will deliver a *Data Report* documenting methods and raw data from vendor.

- This task will be performed by the relevant **Project Staff** and the **Facility Lead**.
- This subtask will deliver *Data Reports*.

5.2 Recordkeeping and reporting

- **Project staff** will keep relevant data as well as preliminary and final work products in the Central Data Repository.
- **Project Manager** will ensure compliance with recordkeeping and reporting requirements.

6.0 Reservoir Design (Task 5)

Subsurface reservoir design is a process that involves planning and engineering the development of underground reservoirs to optimize the injection and/or production of natural or stored fluids. It encompasses various aspects including reservoir characterization, well placement, injection/production strategies, and reservoir management. In the context of gas storage operations, goal is to maximize reservoir deliverability (injectivity and producibility) while minimizing environmental impacts and financial costs.

Standards: API 1171 Chapter 5 (Subchapters 5.4-5.6).

6.1 Pre-drill static geological modeling

Information from Additional Data Collection (Task 4) will be incorporated into the Preliminary Geological Model.

- This subtask will be performed by the **Subsurface Geologist** in association with the **Petrophysicist**.

- This subtask will deliver a *Pre-Drill Reservoir Geology Report* and a *Pre-Drill Static Geological Model* to the **Subsurface Engineer** for simulation.

6.2 Pre-drill reservoir simulation

New reservoir engineering information from Additional Data Collection (Task 4) will be incorporated with the Pre-Drill Geological Model to perform pre-drill reservoir simulations and identify optimal well location(s).

- This subtask will be performed by the **Subsurface Engineer** in association with the **Project Staff** and the **Facility Lead**.

- This subtask will deliver a *Pre-Drill Reservoir Design Report.*

6.3 Area of review evaluation

Review of the data of public record for wells that penetrate that part of the underground porosity reservoir designated as the gas storage porosity reservoir, and those wells that penetrate the reservoir(s) within one-fourth mile of the boundary of the underground porosity gas storage facility.
- Determination if abandoned wells have been plugged in a manner that prevents the movement of gas or associated fluids out of the gas storage test reservoir.
- From the review of public records, identification of any wells that appear to be unplugged or improperly plugged, and any other unplugged or improperly plugged wells for which local or anecdotal knowledge may exist.

- This subtask will be performed by the **Subsurface Engineer** and **Subsurface Geologist** in association with the **Demonstration Lead** and the **Facility Lead**.

- This subtask will deliver a *Preliminary Area of Review Report*.

6.4 Reservoir connectivity analysis

Reservoir Connectivity Analysis (RCA) plays a pivotal role in the evaluation and management of subsurface reservoirs of water, hydrocarbons, CO_2, injected wastewater, and--in the case of this report-hydrogen. RCA involves the examination of pathways though which fluids can flow with the reservoir rock. By understanding the connectivity between different regions of a reservoir, informed decisions can be made regarding well placement, development plans, and long-term injection/production strategies. This analysis typically uses a combination of subsurface geological mapping along with reservoir simulation techniques to model fluid flow behavior.

The insights gained from RCA are crucial for optimizing injection/production operations and reducing/mitigating operational risk. Identifying connected zones withing the reservoir helps in designing effective well patterns and reservoir flow management systems to ensure effective injection/production at maximally efficient deliverability rates. Additionally, it aids in managing reservoir pressure and fluid movement thereby mitigating the risks associated with fluid migration, compartmentalization, and unwanted gas or water breakthrough. Intimately, RCA serves as a foundation for reservoir management practices that ensure efficient and sustainable injection/production cyclicity over the lifetime of the injection demonstration.

The goal of RCA is to identify any possible pathways for injected hydrogen to leak into non-reservoir formations through the caprock/baserock, across a trap spill point, or across a fault into juxtaposed porous formations.

- The **Subsurface Geologist** and **Subsurface Engineer** will perform this analysis using seismic survey and well pressure data.
- This sub-task with deliver a *Reservoir Connectivity Analysis Report*.

6.5 Reservoir pressure analysis

Reservoir Pressure Analysis (RPA) is a fundamental aspect of Subsurface Engineering that provides critical insights into the behavior and characteristics of subsurface reservoirs. RPA involves the measurement, interpretation, modeling, and prediction of reservoir pressure distributions over time. By analyzing pressure data obtained from well tests, pressure gauges, and production histories, reservoir performance can be assessed, and injection/production strategies can be assessed. Understanding reservoir pressure dynamics is essential in ensuring that reservoir development designs take advantage of reservoir drive mechanisms.

RPA also plays a key role in well design and reservoir management decisions. It helps engineers identify potential risks such as fluid ingress form neighboring geological formations, compaction/subsidence, or overpressure conditions that could compromise well integrity or affect injection/production efficiency. Furthermore, RPA facilitates the calibration of reservoir simulation models enabling more accurate reservoir behavior and performance prediction under various operating scenarios.

The goal of the RPA is to identify the pressure envelope (maximum and minimum operating pressures) for the injection demonstration. This ensures the injected gas volumes to not exceed the pressure limits of materials, equipment, or geological formations to be used in the injection demonstration. Staying below a maximum pressure prevents fracturing the caprock and leaking into superjacent geological layers. Staying above the minimum pressure prevents reservoir collapse and subsidence of superjacent strata. It is also

important to identify the impacts of the operating pressure envelope on the corrosive or scaling potential of reservoir and injected fluids with respect to the caprock, reservoir, and baserock formations.

- The **Subsurface Engineer** will perform this analysis using method such as geomechanical gradients (e.g., fracture, water), history of reservoir pressures, caprock petrophysical analysis (e.g., pulse decay permeability analysis, threshold entry pressure analysis, geomechanical analysis).

- This sub-task with deliver a *Reservoir Pressure Analysis Report*.

6.6 Geological penetration analysis

Geological Penetration Analysis (GPA) is a critical aspect of reservoir evaluation and development, focusing on the assessment of the integrity of wellbore placement and construction (including assessment of the plugging effectiveness of abandoned wells). It involves the examination of the wellbore trajectories, depths, and orientations relative to caprock, reservoir and baserock.

By analyzing well penetration data alongside geological and geophysical information, well placement strategies can be optimized to maximize reservoir contact and enhance injection/production rates. This analysis helps in identifying sweetspots within the reservoir where well penetration might be most feasible considering factors such as reservoir thickness, reservoir properties (e.g., porosity, permeability), or fluid properties.

The goal of the GPA is to identify all locations where the caprock, reservoir and baserock have been penetrated by natural (e.g., faulting) or constructed (e.g., wells) features as well as assess the integrity of those features.

- The **Subsurface Engineer** and **Subsurface Geologist** will perform this analysis using well records and well logs. Wells lacking sufficient information will be proposed for additional data gathering.

- The **Subsurface Engineer** and **Subsurface Geologist** will identify possible locations for injection demonstration well and monitoring well(s).

- This sub-task with deliver a *Geological Penetration Analysis Report*.

6.7 Environmental impact analysis

As part of the project's Environmental, Health, and Safety Analysis, an initial Environmental Impact Analysis will be performed to identify risks to the environment from the reservoir design using API Recommended Practices 51R and 76. Specific risks associated with reservoir design relate to how reservoir activities affect surface and underground sources of water. The Environmental, Health, and Safety Analysis will be completed with an Occupational Health and Safety Analysis that will be performed as part of the Well Design

- The **Environmental Scientist** and **Subsurface Geologist** will perform an environmental impact review prior to commencement of construction to identify possible impacts to the environment.

- The **Demonstration Lead**, **Environmental Scientist,** and **Subsurface Geologist** will engage with the relevant local, state, tribal, and federal regulatory bodies to ensure regulatory compliance.

- This sub-task with deliver an *Environmental Impact Analysis Report*.

6.8 Recordkeeping and reporting

During Reservoir Design, specific types of records (e.g., data, reports, maps, permits) will be generated and curated throughout the life of the project. Final disposition of these records will be detailed in the Data Management Plan.

- Geological records (e.g., well logs, reservoir property measured on rocks, reports, maps, geological models)

- Engineering records (e.g., simulation models, injection/production rate data, reservoir property data measured on fluids)

- Property records (e.g., surface ownership maps, mineral rights, maps of distances to sensitive areas)

- Project records (e.g., project reports)

- Well records (e.g., data from well construction, operations, maintenance)

- Regulatory records (e.g., correspondence, permit applications, permits, reports)

- **Project staff** will keep relevant data as well as preliminary and final work products in the Central Data Repository.

- **Data Manager** will ensure compliance with recordkeeping and reporting requirements.

7.0 Well Design (Task 6)

The central technology that will permit the hydrogen injection demonstration will be a new injection/production well that will be drilling in the storage facility. This new well will ensure that a well is designed to meet safety standards and is built with materials appropriate for use with hydrogen. In addition, one or more monitoring wells will be constructed to monitor the hydrogen injection/production demonstration using a suite of sensors place in the reservoir, caprock and superjacent formations (e.g., underground sources of drinking water). It is envisioned that designs from other wells within the facility will be used as the basis for the well design process in this project.

Drilling a well is a complex and multi-faceted endeavor due to several interacting factors:

- ***Geology***: The geological formations through which the well will pass can vary significantly in terms of composition, structure, fluid content, fluid chemistry, and fluid pressure—none of which can be known with absolute certainty until drilling reaches those formations. A successful well design must account for these factors.

- ***Technical challenges***: Drilling invariably encounters unforeseen circumstances in the subsurface that require quick action to maintain well control. These can include loss of circulation or pressure kicks in the mud system or technical challenges like stuck bits or bit drops.

- ***Safety and environmental concerns***: Drilling activities involve numerous hazards including risks of blowouts, fire, and explosions; atmospheric emissions of gasses like hydrogen sulfide (H_2S), and the contamination of underground sources of drinking water. Drill sites can disrupt the habitats of local wildlife.

- ***Regulatory considerations***. Drilling operations are subject to extensive regulatory oversight at the local, state, tribal, and federal levels Compliance with these regulatory regimes requires drilling permits, environmental protection and restoration, and safety standards.

- ***Community and stakeholder engagement***: Communicating early and often with local communities, tribal nations, environmental organizations, and governmental agencies is critical to addressing concerns, managing risks, and maintaining social license to operate.

Drilling a well requires a combination of technical expertise, rigorous planning, advanced technologies, adherence to safety and environmental standards, and effective stakeholder engagement. Successfully navigating these complexities is essential to ensuring the project meets its scientific goal.

This task will be run in parallel for the Injection/Production well as well as the Monitoring Well(s).

Standards: Chapter 6 of the API 1171.

- The **Subsurface Engineer** and **Facility Lead** will lead this task. The **Subsurface Geologist** and other **Project Staff** will participate as appropriate.

- This task will deliver *Well Design Report(s)* for any well to be constructed by the project (e.g., storage well, monitoring well). Well Design Reports will include the sections listed in the remainder of this chapter.

7.1 Wellhead Design

Wellhead equipment will be designed to ensure compliance with appropriate design, materials, and safety standards. Materials and equipment—whether new or existing—will be appropriate for work with hydrogen and at the pressures envisioned for the injection demonstration. Emergency shutdown and isolation valves will be present to support rapid and effective well containment in case of emergency.

7.2 Well Casing and Tubing Design

Well casing is steel pipe that acts as the first barrier between well fluids and geological formations that are not intended to be the locations of injection or production.

Casing and Tubing Design will ensure 1) protection of groundwater, 2) proper control of well pressures, and 3) attainment of scientific objectives. For the injection demonstration well, the scientific objectives include the injection of hydrogen to and the withdrawal of hydrogen from the reservoir formation. For the monitoring well(s), the scientific objectives include performing scientific measurements of chemical and physical properties in the reservoir, caprock and other geological formations.

Standards: API Specification 6A/6D for general well design standards, API Specification 14A/B for subsurface safety valves, US Code 49 CFR 192.145 for pipeline safety valves, API Recommended Practice 14E for calculating tubing velocities, API Recommended Practice 5C1//5C5 And Technical Report 5C3 for casing and tubing handling, and API Specification 5CT for casing and tubing specifications.

7.3 Well Casing Cement Design

The Casing Cement Design will ensure integrity of the wellbore by further isolating the wellbore environment where injection or production fluids are flowing from geological formations not of interest.

Standards: API Specification 10A and ASTM C150/C150M for cement quality standards. API Recommended Practice 10D-2 and API Technical Report 10TR4 for casing centralization methods and cementing evaluation.

7.4 Well Barrier Assessment

Once the wellhead, casing and casing cement designs are in place, they will be evaluated as a “well barrier system” and this system’s performance in separate wellbore fluids from the natural environment will be assessed. The barrier system can be divided into the parts of the system that are exposed to wellbore fluids (primary barrier) and those that are not (secondary barrier).

If the integrated system does not provide adequate containment of wellbore fluids, wellhead, casing, and casing cement designs will be re-evaluated to ensure proper containment.

Standards: ISO 16530-1 for barrier systems and performance evaluation.

7.5 Well Completions and Stimulations Design

Well completions and stimulations are the final stage in well construction where the well is prepared for injection or production. This involves the placement of equipment such as production casing/tubing/liners

and downhole tools to facilitate fluid flow and provide structural support to the wellbore. The completion process includes perforating the casing or liner to create pathways for fluids to flow between the wellbore and reservoir. Various completions can be used including open-hole completions, cased-hole completions and gravel packing.

- The injection demonstration well will likely use a cased hole completion because that is common in modern gas storage wells.

- The monitoring well(s) may use a variety of completions method depending on the goals of the monitoring program.

Well stimulation is the process of improving the injectivity or producibility of a reservoir rock. This is necessary when the reservoir rock has low permeability or has been damaged during drilling. Stimulation techniques typically involve the injection of fluids or proppants into the reservoir at high pressure to create or enhance fractures in the reservoir rock, thereby increasing reservoir permeability. Common techniques include hydraulic fracturing and acidizing.

Standards: API Guidance Document HF1/HF2/HF3, API Recommended Practice 100-1 for guidance on hydraulic fracturing.

In a report issued by the US Well Integrity Working Group in the wake of the Aliso Canyon Incident (Freifeld et al., 2017), it was recommended that "A quantitative cost-benefit analysis of downhole safety valves is needed to resolve uncertainty in their benefit for the U.S. natural gas storage industry." The Project will conduct such a review.

- This subtask will be performed by the **Subsurface Engineer** in association with the **Facility Staff**.

- This subtask will deliver *Ancillary Report 1: Subsurface Safety Valve Report*.

7.6 Well Monitoring Plan

This subtask will test two hypotheses:

***Hypothesis** 7* that "artificial intelligence and machine learning can be employed to sift through monitoring data to identify significant events and trends in monitoring parameters to identify wellbore leaks." This hypothesis will be tested by having AI/ML routines watch incoming data from the demonstration injection to establish baseline telemetry data that could be used to identify concerning events or trends.

Hypothesis 8 that "current chemical hydrogen monitoring devices can detect leaking hydrogen from surface facilities and equipment." This hypothesis will be tested by setting up leak monitoring protocols to ensure hydrogen presence is tested at various distances from major pieces of process equipment (e.g., wellhead, compressor, dehydrator, pipe connections) to identify how close detectors need to be to identify leaks. In addition, local (e.g., infrared) and remote (e.g., satellite) sensing technologies will be tested to determine the extent to which measurement could be made from even further afield which may improve the economics of site monitoring.

7.7 Well Testing Plan

Well testing encompasses several types of testing procedures that make physical measurements (e.g., temperature, pressure) or take samples of fluids within the wellbore. These can provide valuable assessments of well integrity or information of formation fluid properties.

Well Testing Plan will include mechanical integrity testing and a casing inspection log for each new casing string.

7.8 Well Remediation Plan

If a well is unable to maintain mechanical integrity, appropriate response methods will be evaluated and implemented. These could include remediation to restore integrity, reconfiguration, temporary abandonment, or permanent abandonment.

Standards: Section 8 of API Recommended Practice 1171 has details on integrity monitoring and management.

7.9 Well Closure Plan

When the project's well activities have reached their conclusion, the wells will be transferred to a responsible party (e.g., the Facility Lead), another entity, or permanently plugged and abandoned.

Obtaining title to the wells may act as an incentive to encourage participation in project activities by the Facility Lead. It also ensures alignment between project and Facility Lead to the future interest in the well by the Facility Lead.

If the well is to be plugged and abandoned, relevant regulations will be followed (e.g., design of cement plug and mechanical packers).

Standards: API Bulletin E3 for guidance on well abandonment procedures, US Bureau of Safety and Environmental Enforcement Report RLS0116 for cement plug information.

7.10 Occupational Health and Safety Analysis

Drilling wells present unique and significant safety risks due to the remote work locations, 24/7 operations, coordination between numerous contractors, and the uncertainty inherent in drilling operations.

The **Facility Lead** will ensure that the facility's safe work program is applied at drill sites. This will be communicated to any **Project Staff** who perform site visits.

Standards: API Recommended Practices 49, 51, 54, 76 related to well design safety.

7.11 Construction Quality Assurance Plan

Due to the complex nature of drilling operations, it is recognized that the Facility Lead will likely hold the core competence in assuring quality and safety of drilling operations.

- **Facility Lead** will take lead in assuring quality of drilling programs.

- **Project Manager** will facilitate any needs of **Facility Lead** from **Project Staff**

7.12 Provisional Permit Application

- **Facility Lead** will submit application to relevant regulatory bodies for permits related to drilling project wells.

- **Project Manager** will coordinate with **Project Staff** to fill out permit applications and maintain open communication with regulators along with **Demonstration Lead**.

7.13 Recordkeeping and Reporting

During this task, specific types of records (e.g., data, designs, schematics, test records, material formulae and recipes, maps, permits, simulation reports) will be generated and curated throughout the life of the project. Final disposition of these records at project end will be detailed in the Data Management Plan.

- **Project staff** will keep relevant data as well as preliminary and final work products in the Central Data Repository.

- **Project Manager** will ensure compliance with recordkeeping and reporting requirements.

8.0 Site Security Planning (Task 7)

This task is based on Chapter 10 of the API 1171.

8.1 Site Security Plan

A Site Security Plan (SSP) outlines the measures and procedures designed to protect a location, facility, or property from unauthorized access, theft, vandalism, terrorism, or other security threat. This plan is developed to address potential security risks and vulnerabilities as well as to ensure the safe and security of personnel, assets, and information with the project site. It is important to recognize that information security (also known as cybersecurity, API 1164) is an integral part of site security.

Components of the SSP will include:

- ***Risk assessment***: identification and evaluation of potential security threats and vulnerabilities specific to the site including physical, cyber, and personnel-related risks.

- ***Security measures***: Description of security measures and controls to mitigate identified risks, such as access control systems, perimeter fences, surveillance cameras, security personnel, alarm systems, and security policies/procedures.

- ***Emergency response procedures***: Protocols for responding to security incidents, emergencies, or threats including evacuation procedures, communication protocols, and coordination with emergency responders.

- ***Training and awareness***: Training programs and awareness initiatives to educate personnel about security risks, procedures, and their roles and responsibilities in maintaining site security.

- ***Incident reporting and investigation***: Procedures for reporting security incidents, conducting investigations, documenting findings, and implementing corrective actions to prevent recurrence.

By developing, implementing, and iteratively improving the SSP the project will enhance its ability to prevent security breaches, protect assets/personnel, and respond effectively to emergency situations. Additionally, adherence to security standards and regulations as well as regular review and updates of the security plan are essential for maintain the effectiveness of site security over the lifetime of the injection demonstration project.

Because the envisioned injection demonstration will occur at an existing natural gas storage facility, the project will follow the established SSP for that facility.

- The **Demonstration Lead** and **Project Manager** will work with the **Facility Lead** to review the facility's SSP and amend it where appropriate to account for operations related to the project.

- This task will deliver a *Site Security Plan* that will likely be reported as part of regulatory compliance.

8.2 Recordkeeping and reporting

- **Project Manager** will ensure compliance with recordkeeping and reporting requirements.

9.0 Pre-Drill Risk Analysis (Task 8)

This task is based on Chapters 8 and 11 of the API 1171. In this task the preliminary risk analysis is revisited and amended as necessary and safe work procedures are developed in advance of drilling project wells. This risk analysis should not be considered final and be updated as new pertinent information is obtained.

- The **Demonstration Lead** and **Project Manager** will work with the **Facility Lead** to update the Risk Management Plan.

- This task will deliver a *Pre-Drill Risk Management Plan* updating the *Preliminary Risk Management Plan*.

9.1 Culture of Safety

A Culture of Safety will be a core value of the project. It will be modeled, promulgated, and managed by the **Facility Lead** and the **Demonstration Lead**.

9.2 Management of procedures

Facility procedures will be owned by the **Facility Lead**, who will exercise their authority to ensure the safety of the Facility, its people, and the environment. The **Facility Lead** has ultimate authority to decide whether the demonstration proceeds at any stage of the demonstration. The **Facility Lead** will ensure novel operational procedures that would be inherent in the Project will be integrated with facility procedures, including:

- Environmental, health, and safety programs

- Field control systems

- Operation and maintenance procedures

- Well construction procedures

9.3 Identify preventative and mitigative measures

Facility Staff and **Project Staff** will meet regularly to review demonstration performance and identify any preventative or mitigative procedures that may be necessary to accommodate demonstration performance

9.4 Operations and maintenance procedures

The Project will follow the Facility's management system for operations integrity as closely as possible, working with the **Facility Lead** to modify procedures and promulgate those procedures to both Facility Staff and **Project Staff**.

9.5 Well construction and maintenance procedures

The Project will follow the Field Site's well construction and maintenance procedures (including any associated Management of Change procedures as closely as possible, working with the **Facility Lead** to modify procedures and promulgate those procedures to both Facility Staff and **Project Staff**.

9.6 Public engagement

The **Facility Lead, Demonstration Lead,** and the **Communications Manager** will ensure appropriate public engagement regarding risks associated with the Project.

9.7 Periodic review of and update to procedures

The **Facilities Lead** and **Demonstration Lead** will review procedures quarterly (or more frequently as appropriate) to determine if any changes to operational procedures are warranted.

9.8 Recordkeeping and reporting

- **Project Manager** will ensure compliance with recordkeeping and reporting requirements.

10.0 Well Construction and Testing (Task 9)

This task is based on Chapter 6 (Subchapters 6.10-6.12) and Chapter 7 of the API 1171.

- The **Demonstration Lead, Project Manager,** and **Project Staff** will work with the **Facility Lead** to execute well construction and testing.

- This task will deliver *Well Construction Report(s)* documenting well construction and *Data Reports* documenting data collection methods and raw data from vendors. Responsible parties are listed below.

10.1 Well Construction Plan

10.1.1 Drilling

Drilling a well is a very complex engineering and logistical operation and thus is best left to commercial drilling vendors due to the significant repercussions of improper operations. Drilling operations generally run 24/7, regardless of weather, until construction is complete.

- Drilling program goal: execute well construction program safely with respect to the environment, human health, and occupational safety.
- Drilling program goal: construct a hydrogen injection/withdrawal well and a monitoring well according to design.
- Well construction will be accomplished with commercial oilfield drilling services company.
- **Demonstration Lead** and **Facility Lead** will develop well construction schedule with **Vendors** (e.g., Driller, Well Logging Vendor) to ensure scientific objectives are met.
- All parties are empowered to report unsafe conditions and stop operations until such conditions are remedied.

10.1.2 Sampling and Analysis Plan

Well construction is one of the first phases when physical samples will be collected in volume and at a high tempo. Within the context of the demonstration project and the chosen site, the project team will establish a rigorous sampling plan with clearly enumerated Data Quality Objectives (USEPA, 2006) using PNNL's Visual Sample Plan tool (PNNL, 2024). The contents of this section outline broad sample type categories and provides justification for collecting those samples, and examples of how they can be analyzed. The specific project will decide type, quality, quantity, and amount of samples as well as the procedures and frequency with which they are collected.

Members of the sampling and analysis planning team: **Demonstration Lead**, **Project Manager**, and **Project Staff.**

10.1.3 Casing/Cementing

Cement and casing are key components in ensuring well integrity and the protection of other subsurface layers (such as underground sources of drinking water). ***Casing*** is steel pipe with threaded ends that are screwed together and lowered into the wellbore to provide the fundamental barrier between the open conduit of the well and surrounding rock layers. Because it is impossible to perfectly manufacture casing to account for the irregularities of the borehole, the outer diameter of the casing is a smaller diameter than

the borehole. Into the space between casing and rock (the so-called annular space or annulus), liquid ***cement*** is pumped down the center of the casing and back up into the annular space. This cement forms a secondary barrier between the open conduit of the well and surrounding rock layers. Within the casing, *production tubing or liners* are installed to further separate injection/production fluids from the surrounding rock layers.

- This subtask will test ***Hypothesis 6.1*** that "the blend of cement used in wells at salt cavern facilities storing hydrogen would provide adequate performance at a porous media facility storing hydrogen." This could be tested by collecting rotary sidewall cores of wellbore cement before and after storage demonstration to assess any alteration of the cement in the presence of hydrogen. Different cement compositions (e.g., with and without resin additives) could also be use at different depths in the well bore.

- As part of this subtask, **Ancillary Report 2: Comparison of the effectiveness of different casing evaluation tools**, will be written and will include an assessment the ability for ultrasonic tools to be used for casing inspection in wellbore containing hydrogen. This report will be written by the **Petrophysics Lead**.

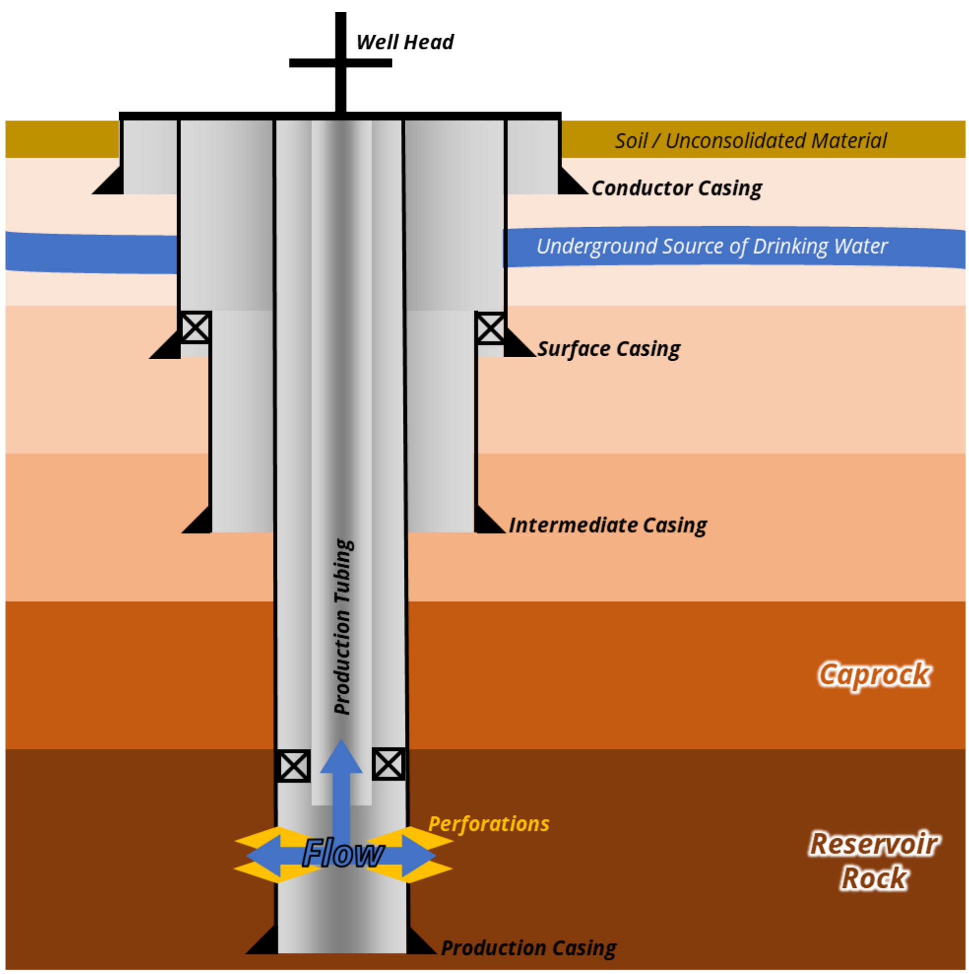

Figure 5: Schematic of types of casing and location of cement.

Four types of casing are found in most deep wells for oil, gas, or gas storage applications: conductor, surface, intermediate, and production.

- Any intermediate or production casing strings or liners that are set in the wellbore will be cemented with a sufficient volume of cement to fill the annular space to the surface.
- All casings, tubings, and liners will meet the standards specified in best practice documents for casing and tubing.
- All casings, tubings, and liners will be new casing or reconditioned casing of equivalent quality that has been pressure-tested in accordance with the regulatory requirements.
- Verify emplacement of cement by running a cement bond log, cement evaluation log, or other regulator-approved evaluation method.
- Borehole and casing schedule will depend on the depth of reservoir chosen for the test (Table 3).

Fiber optic temperature and/or acoustic sensor technology will be integrated into the well construction to test **Hypothesis 7** that "artificial intelligence and machine learning can be employed to sift through monitoring data to identify significant events and trends in monitoring parameters to identify wellbore leaks." This hypothesis could be tested by having AI/ML routines watch incoming data from the demonstration injection to establish baseline telemetry data that could be used to identify concerning events or trends.

Table 3: Example casing configurations for gas storage wells of varying total depths (~500 ft to ~7000 ft) in Kansas (Source: Kansas Geological Survey Website, 2024).

Well (Field) Name	Total Depth (ft)	Casing Type	Hole Size (in ID)	Casing Size (in OD)	Weigh t (lb/ft)	Setting Depth (ft)	Cement Type	Sacks used (n)
North Liberty #403 (Liberty N Field)	546	Surface	12.25	8.625				
		Production	7.875	5.5	15.5	442	Circ	70
South Welda #56 (Welda S Field)	963	Surface	12.25	10		6		
		Production	9	7		649	Class A	130
		Liner	In 7" casing	4.5	11.6	912	OWC	93
McLouth 20 (McLouth Field)	1366	Surface	14	1.275	23	7	Class A	7
		Production	9	7	20	1463	Class A	467
		Liner	In 7" casing	4.5	10.5	1430	OWC	236
Fair O-26 (Alden Field)	3550	Surface	12.25	8.625	24	511	Class A	325
		Production	7.875	4.5	10.5	3534	A-Con	650
Alley 16-44 (Cunningham Field)	4452	Conductor	30	24	94	130	A	150
		Surface	17.5	13.375	54.5	298	H-Con	360
		Intermediate	12.25	9.625	40	1687	H-Con	1005
		Production	8.75	7	23	4446	H-Con	1085
Bartel 1-5 (Borchers N Field)	6833	Conductor	22	20	53	62		162
		Surface	12.25	8.625	28	2541	H, HLC	1600
		Production	7.875	17	10.5	5928	Midcon C	365

10.1.4 Drill Cuttings

Drill cuttings are composed of the rock debris pulverized by the drill bit during the normal course of drilling and returned to the surface in the drilling fluid (i.e., mud). Because coring usually only occurs in specific depth intervals, drill cuttings provide tangible samples from the entire length of the wellbore. They are useful in identifying which formations are being traversed by the drill bit and thus are useful in verifying pre-drill depth predictions so casing and coring points can be picked more accurately. In addition, some jurisdictions have regulations about how often to collect cuttings samples and whether they should be delivered to a repository.

- *Data Quality Objectives:* Document geological properties of cuttings during well construction to identify what formation the drill bit is in to compare with pre-drill to ensure mud weight aligns with pore pressure prediction.

- *Sampling Procedures:* Two sets of cuttings will be collected at least as often depth-wise (e.g., every 10 feet) as regulations require. One set will be an archive set and sent to the state repositor. The other will be a research set that will be available for scientific analysis such as:
    - Calibrating the response of geochemical logs via geochemical analysis
    - Pulse decay permeametry in sealing intervals

- *Drill Cuttings Visual Description:* Drill cuttings will be visually described by the **Wellsite Geologist** using a system approved by the **Subsurface Geologist**. The wellsite geologist will prepare a geological log during drilling operations as cuttings samples are collected. This log will be reported publicly as regulations stipulate.

10.1.5 Drilling fluids and Makeup Water

- *Data Quality Objectives:* Document chemical and physical properties of drilling fluids during well construction.

- *Sampling Procedures:* **Wellsite Geologist** (or contractor like an onsite mud engineer) will collect drilling fluid and makeup water periodically.

- *Sample Analysis Program:* Samples will be analyzed onsite or sent to **Fluid Analysis Vendor** for analysis and tested for major and trace elements. Data will be interpreted by **Subsurface Engineer**, **Subsurface Geologist**, and other project staff.

10.1.6 Drilling Fluid Gas

- *Data Quality Objectives:* Document chemical and physical properties of drilling fluid gases during well construction.

- *Sampling Procedures:* **Wellsite Geologist** will run mud gas analyzer during well construction to collect volumetric compositions of drilling fluid gasses. Gas samples will be collected periodically and shipped to vendor for analysis.

- *Sample Analysis Program:* Samples will be sent to **Fluid Analysis Vendor** for analysis and tested for volumetric composition of H, He, N, CO_2, H_2S, CH_4, H_2O, and Ar as well as isotopic composition of CO_2 ($\delta^{13}C$, $\delta^{18}O$), H_2O ($\delta^{2}H$, $\delta^{18}O$), and CH_4 ($\delta^{13}C$, $\delta^{2}H$), and H_2S ($\delta^{2}H$, $\delta^{34}S$). Data will be interpreted by **Subsurface Engineer**, **Subsurface Geologist**, and other project staff.

10.1.7 Drilling Fluid Makeup Water

- *Data Quality Objectives:* Document chemical and physical properties of drilling makeup during well construction.

- *Sampling Procedures:* **Wellsite Geologist** will collect makeup water samples periodically.

- *Sample Analysis Program:* Samples will be sent to **Fluid Analysis Vendor** for analysis and tested for major and trace elements. Data will be interpreted by **Subsurface Engineer**, **Subsurface Geologist**, and other project staff.

10.1.8 Coring

Coring is the process of bringing intact rock cores from subsurface formation to the surface for geological description as well as geochemical and petrophysical analysis. In most oil-, gas-, and gas storage fields, rock cores are four inches in diameter and collected in 30-foot lengths. Coring is expensive because this coring barrel must be tripped into and out of the hole for every 30 feet of rock cored. Because of this expense, no well is every continuously cored from surface to total depth (TD), but rather specific intervals of interest are chosen, usually focusing on the reservoir and caprock intervals.
Despite this expense, coring is a vital component of evaluating the reservoir and caprock intervals to assess their ability to meet the designed parameters of the hydrogen injection program. This assessment includes both the physical rock matrix as well as any fluids and microbial communities that exist in their porespace.

Rock cores are vital to interpreting well logs because they allow petrophysical and geochemical signals to be interpreted in terms of real rock material. Because every well is logged, but perhaps only 1% of wells are cored.

- *Data Quality Objectives:* This projects core analysis program must provide sufficient material for routine core analysis program (RCAL, vendor), special core analysis program (SCAL, vendor), and research core analysis program (ResCAL, national laboratories and universities).

- *Sample Collection Procedure:* Continuous core the entire thickness of the caprock and reservoir interval(s).

- *Sample Analysis Program:* Core will be analyzed at a **Core Analysis Vendor**.

- **Core Analysis Lead** will be responsible for designing and executing the core analysis program as well as interfacing with **Drilling Vendor** and **Core Analysis Vendor**.
- **Core Analysis Lead** will be responsible to update coring points (depths at which to start/stop coring) based on drilling progress.
- **Core Analysis Lead** will be onsite as cores are extruded to perform wellsite core description and photography, and identify sections for preservation, before shipping cores to **Core Analysis Vendor**.
- **Core Analysis Lead** in concert with the **Petrophysics Lead** will determine core-to-log depth corrections so core analysis vendor can mark log-corrected depths on cores during curation.

10.1.9 Well Logging

Well logging (also called geophysical or petrophysical logging) involves lowering a suite of sensors down the wellbore to measure physical and chemical properties of the rocks and fluids that are adjacent to the borehole. Well logging is generally done in every deep oil, gas, or gas storage well due to being relatively inexpensive, especially if only the depth intervals of interest are logged. For example, it is often customary to only log the open borehole from TD up to the intermediate casing shoe, though in most exploratory/wildcat/research wells, as much of the open borehole as possible is generally logged. Specific well logs (e.g., density) are required for generating a synthetic seismogram which allows for seismic survey data to be accurately converted form the time domain in which it was acquired to the depth domain so it can be correlated with drilling data.

Every logging sensor has different vertical and lateral resolution within the borehole, known as the "zone of investigation" (Figure 6).

- *Data Quality Objectives:* run full suite (Table 4) of downhole logging tools in open boreholes from TD to surface, including before any intermediate casing is run to ensure a continuous set of measurements from TD to as close to the surface as possible.
- **Petrophysics Lead** will be responsible for designing and executing the petrophysical analysis program as well as interfacing with **Drilling Vendor** and **Logging Vendor**.
- **Petrophysics Lead** will work with **Core Analysis Lead** to perform core-to-log correlation

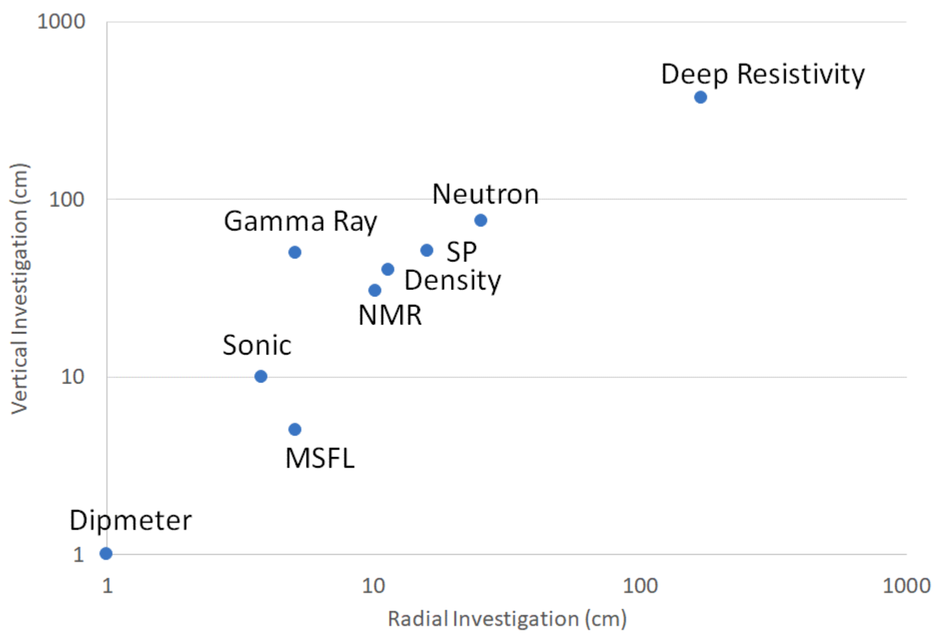

Figure 6: Radial and vertical distances common well logging tools investigate. These combine into a volume or "zone" of investigation.

10.1.10 Formation fluid from high-permeability zones

- *Data Quality Objectives:* Measure the chemical and physical properties of water from high-permeability zones (e.g., reservoirs) encountered during drilling.

- *Sampling Procedures:* Wellsite Geologist will collect samples from the DST tool and send to **Fluid Analysis Vendor.**

- *Laboratory Analysis Program:* Samples will be sent to **Fluid Analysis Vendor** for analysis and tested for major and trace elements. Data will be interpreted by **Subsurface Engineer**, **Subsurface Geologist**, and other project staff.

10.1.11 Open hole testing

Open hole engineering tests are vital to collecting large-scale data about the performance of the reservoir-seal system by, for example, measuring the fracture gradient *in situ*. These tests can include:

- Step-rate test
- Mechanical integrity test
- Open-hole fluid logging test
- Low-permeability interval packer test
- High-permeability interval packer test
- Hydraulic fracture stress measurement
- Sleeve reopening of hydraulic fracture
- Push-pull tracer test

- *Data Quality Objectives:* Measure the chemical and physical properties of the well.

- *Sampling Procedures:* **Subsurface Engineer** will be onsite to monitor well testing as appropriate.

Table 4: Well logging tools to be used for formation evaluation program in this study along with purpose (after Kuhlman et al., 2019).

Property	Tool Type	Purpose
Borehole Morphology	Deviation Survey	Borehole azimuth and inclination measurements ensure borehole is within design limits.
Borehole Morphology	Caliper, Micro-resistivity Image Logs	Determine location, orientation and spacing of fractures, faults, bedding, vugs, mineralization. Provide 3D borehole visualization. Determine horizontal stress orientations from breakouts or fractures. Essential for calibration and interpretation of many wireline logs (providing directionality). Calibration data for orienting cores. Useful for selecting packer and sidewall core locations.
Lithology	Spectral Gamma-Ray	Identify lithology. Correlate strata with adjacent wells. Increase quality of core-to-log calibration.
Lithology	Photoelectric Factor	Identify mineralogy for constructing lithology logs.
Lithology	Pulsed Neutron	Identify chemistry of rock for constructing lithology logs.
Stress	Shear Wave Anisotropy	Identify direction and magnitude of the maximum and minimum horizontal stresses.
Stress, Porosity	Full Waveform Sonic	Estimate porosity and rock hydromechanical properties. Useful for interpreting VSP data and constructing synthetic seismograms (seismic-well ties). Estimate horizontal stress anisotropy from shear-mode seismic waves.
Porosity	Gamma Density	Estimate formation bulk density and porosity. Input for design of VSP survey. Required for seismic-well tie.
Porosity	Neutron Porosity	Estimate water or hydrocarbon content and therefore porosity at high resolution over smaller volumes than gravity. Best used with gamma density log.
Porosity	Nuclear Magnetic Resonance	Estimate porosity, tortuosity, and pore size distribution, which can be used to estimate permeability.
Fluid	Resistivity	Interpretation of fluid presence/type/salinity, lithology, and permeability.
Fluid	Spontaneous Potential	Identify lithology, mineralization, and fluid salinity. Correlate strata with adjacent wells.
Fluid	Induced Polarization	Estimate formation chargeability, a function of solid-liquid interface that can be related to permeability.
Temp.	Temperature	Estimate geothermal gradient. Provides required temperature corrections for other wireline logs.
Temp.	High-Resolution Temperature	Identify groundwater inflow and outflow features from small-scale variations in borehole fluid temperature.
Quality Assurance	Cement Bond Log	Inspect quality of cement in filling annular space.

10.1.12 Completions

It is recommended that gas injection or withdrawal wells located within 330 feet of an inhabited residence, commercial establishment, church, school, or small, well-defined outside area will be equipped with down-hole safety shutoff valves (API RP 1171).

All wellhead components, including the casinghead and tubing head, valves, and fittings, will be made of steel having operating pressure ratings sufficient to exceed the maximum injection pressures computed at the wellhead. These ratings will be clearly identified on valves and fittings. The wellhead master valve on each gas storage well will be fully opening and sized to the diameter of the casing or tubing string to which the valve is attached. Each flow line connected to the wellhead will be equipped with a manually operated positive shutoff valve located on the wellhead.

A cased hole formation log will be run to identify location of casing with respect to geologic formations outside the wellbore.

10.2 Core analysis and curation

Core analysis and curation involves laboratory work done on rock cores. Typically, limited curation is done at the well site after the core is extruded from the core barrel. Then the core is secured for transport to a dedicated facility that houses specialized equipment. Some work is fairly standard procedure and is carried out by personnel of the **Core Analysis Laboratory** (e.g., core marking, photography, core plugging, routine and special core analysis tests). However, it is important for project representatives to maintain open communication and perform watchful quality control on procedures and resulting data. In addition, some key steps in the core analysis process require on-site visit by relevant **Project Staff**.

Additional trim end material will be used for major element analysis by X-ray fluorescence and analysis of relative abundance of mineralogies via X-ray diffraction. This information will be used to calibrate lithology logs.

10.2.1 Preserved whole cores

Whole core sections would be cut on rig site as soon as possible and preserved (e.g., plastic wrapped, aluminum foil wrapped, dipped in wax) to preserve core samples in as close to reservoir conditions as possible. Whole cores would be 8-10 inches long. The remainder of the core will be sealed in the liner and shipped to the **Core Analysis Laboratory**.

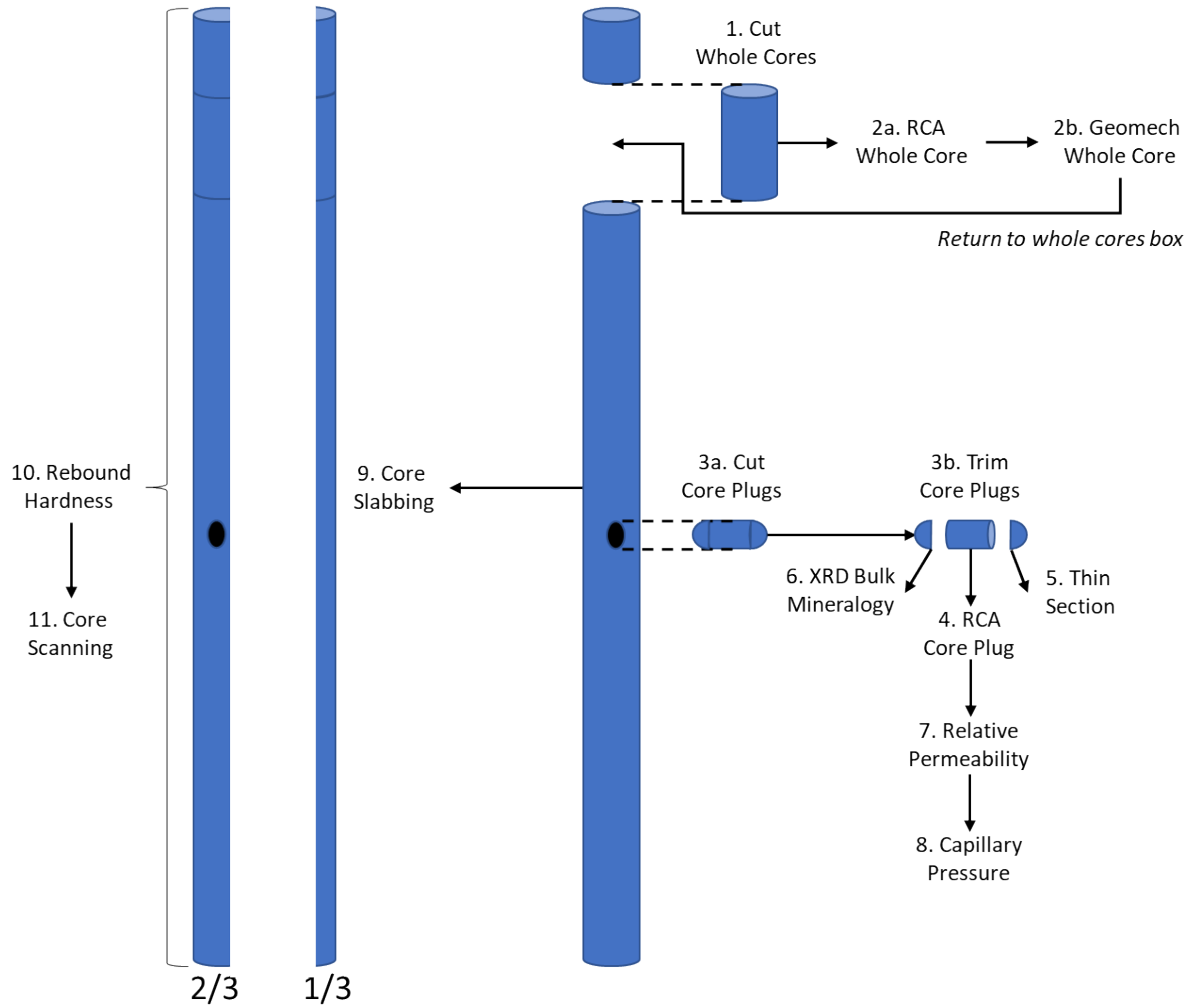

Figure 7: Workflow showing how core material moves through various stages of core analysis.

10.2.2 Core analysis lab core scanning

X-ray scanning. Upon arrival at the Core Analysis Lab, all cores (preserved and those sealed in liner) will receive 2D X-ray radiographs for picking core plug locations. To be performed by **Core Analysis Laboratory**.

Spectral gamma ray scanning. All cores will be subjected to natural gamma ray scanning for accurate correlation to gamma ray well log. To be performed by **Core Analysis Laboratory**.

10.2.3 Plug picking party

Core Analysis Lead, Petrophysical Lead, and other interested project personnel will view core X-rays and pick locations for collection of core plugs and additional whole cores.

10.2.4 Core curation and plugging

Core Analysis Laboratory. Personnel will extrude cores from liners and add appropriate depth markings along with red and black marker lines to denote core up-direction. Plugging for routine core analysis (RCAL) will occur down the medial axis of the core so that the longest possible core plug is obtained. Plugging for certain special core analysis tests (SCAL, e.g., relative permeability) may occur at closer spacing (e.g., hexagonally closest packed) to maximize the number of plugs that can be recovered in a single facies.

10.2.5 Routine core analysis (RCAL)

RCAL will obtain basic reservoir rock properties on 1.5-inch diameter core plugs and whole cores after Dean-Stark extraction of any hydrocarbon residue. Porosity and grain density will be measured using Boyle's Law pycnometry. Klinkenberg-corrected permeability will be measured via steady state analysis for reservoir rock or unsteady state analysis for caprock. Both measurements will be performed at reservoir stress conditions.

10.2.6 Special core analysis (SCAL)

Relative Permeability. This test will be run on multiple core plugs to measure the relative permeability of hydrogen in a gas saturated reservoir. This will provide valuable calibration data for dynamic reservoir simulation in building accurate predictions of the flow behavior of hydrogen in the reservoir rock.

Threshold entry pressure (TEP). This test will be run on select core plugs from the reservoir rock and caprock to understand entry pressure for a rock type's pore system with respect to hydrogen, which is valuable in understanding its capillary failure threshold.

Mercury injection capillary pressure (MICP). This test will be run on select core plugs or trim ends from the reservoir rock and caprock to measure the pore throat size distribution, which exerts a fundamental control on permeability. This test is destructive because the samples are left contaminated with mercury.

Nuclear magnetic resonance (NMR). This test will be run on select core plugs from the reservoir rock and caprock to measure the pore size distribution, which is useful in understanding pore system heterogeneity of the reservoir rock and caprock. This test is also valuable for calibrating the NMR wireline well log. This test is run on core plugs and is non-destructive.

X-ray diffraction (XRD). This test will be run on a trim end from each core plug to identify the relative abundance of mineralogies present in each plug. This will help in understanding the bulk mineralogical and chemical makeup of the reservoir rock and caprock.

10.2.7 Rock mechanics

Micro-CT of plugs. This test will be run on each core plug to identify internal structural features that may affect geochemical testing.

Geomechanical testing. Triaxial Compressive Strength Strain Rate of 1e-6 in/in/sec – measure Static Young's Modulus, Poisson's Ratio, Yield Strength, Peak Strength with Dynamic Properties.

10.2.8 Lithological/mineralogical Analysis

Trim ends from 1.5-inch RCAL core plugs will be used to manufacture oversize (2x3-inch) thin sections. Epoxy will be dyed blue and doped for fluorescence to aid in petrographic analysis of pore systems. Half of thin sections will be dyed with mineralogical stain appropriate for the lithology of the thin section. This information will be used to build facies models for the static geological model.

10.2.9 Core splitting and photography

Whole cores will be re-integrated at accurate intervals. The core will be slabbed longitudinally into one-third (archive) and two-thirds (working) pieces. The archive thirds will be archived in “slab packs”, of approximately 10 feet per box. The archive two-thirds will be archived in whole core boxes, approximately 3 feet per box.

10.2.10 NETL core scanning

All DOE-funded projects that collect rock cores are requested to send core material to the NETL core scanning lab to have additional petrophysical and geochemical core scanning performed. These tests include:

- 3D X-ray computed cosmography scanning
- X-ray fluorescence (XRF) geochemical scanning
- Spectral gamma ray scanning
- Acoustic (p-wave) scanning
- Computed tomography (CT) scanning

10.2.11 Core description

With curated cores, the **Core Analysis Lead** will describe the geological and pore system features of the rock cores using thin sections, well logs, routine and special core analysis data, and core photographs. An overarching goal of the core description will be 1) the construction of a stratigraphic architecture of the reservoir rock and cap rock and 2) the correlation of geological features and stratigraphic architecture with well log signals.

Rebound hardness will be measured via Schmidt hammer to provide high resolution quantitative data on reservoir rock and geomechanical properties hardness.

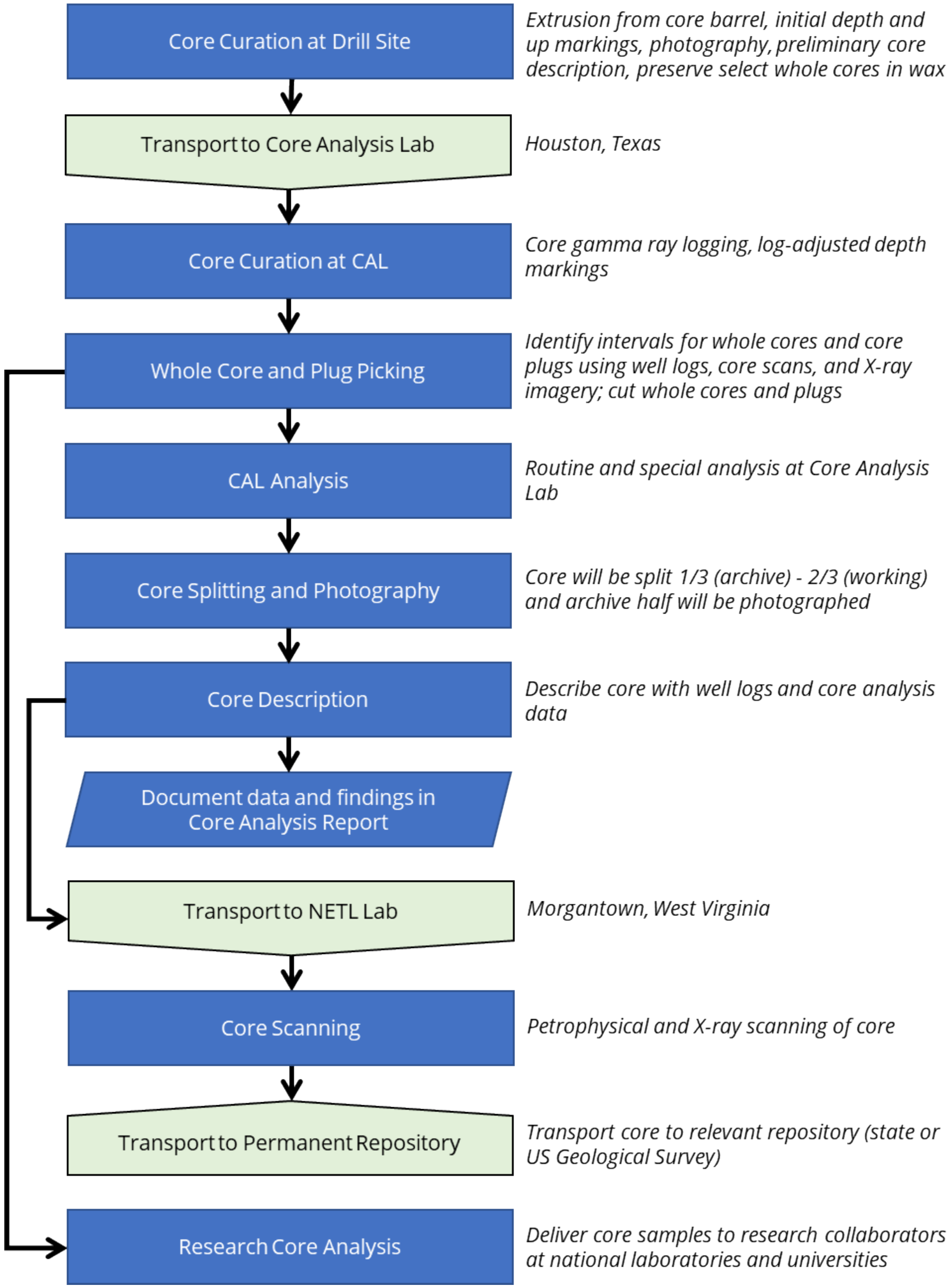

Figure 8: Core analysis workflow.

10.2.12 Research core analysis (ResCAL)

Samples of rock core and fluids may be delivered to specific academic or national laboratories at any point in the core analysis workflow as deemed necessary, this will depend on existing data available for the site in question, and availability/suitability of preexisting core for research analysis.

10.3 Surface and Environmental Monitoring

Near-wellbore and environmental monitoring further afield will be undertaken to identify leaks from project equipment as well as identify and environmental impact.

This subtask will test ***Hypothesis 8*** that "current chemical hydrogen monitoring devices can detect leaking hydrogen from surface facilities and equipment." This hypothesis could be tested by setting up leak detectors at various distances from major pieces of process equipment (e.g., wellhead, compressor, dehydrator, pipe connections) to identify how close detectors need to be to identify leaks. In addition, local (e.g., infrared) and remote (e.g., satellite) sensing technologies to be tested to determine the extent to which measurement could be made from even further afield which may improve the economics of site monitoring.

10.4 Recordkeeping and Reporting

- **Project Manager** will ensure compliance with recordkeeping and reporting requirements.

11.0 Underground Hydrogen Storage Demonstration (Task 10)

The signature activity of this report is a demonstration of underground hydrogen storage, and this demonstration commences in this task and runs for a period of approximately two years so it can observe what would be analogous to approximately two full injection/production cycles of a traditional natural gas storage reservoir.

For the duration of the injection demonstration, most work will involve monitoring of system performance, well and reservoir integrity, and operational safety. In addition, periodic updates to the static geological model and engineering simulations will occur as new data or understandings are gleaned from the performance of the injection demonstration.

This task is based on Chapter 9 of the API 1171.

- The **Demonstration Lead, Project Manager,** and **Project Staff** will work with the **Facility Lead** to execute the demonstration.

- This task will deliver *Underground Hydrogen Storage Demonstration Report(s)* documenting well construction and *Data Reports* documenting data collection methods and raw data from vendors. Responsible parties are listed below.

11.1 Well integrity monitoring

This subtask will evaluate two hypotheses:

- ***Hypothesis 5.1*** that "fiber optic sensing can be utilized to monitor the connection points between wellbore steel for hydrogen leaks." This could be tested by installing fiber optic sensors during well construction that could monitor for leaks at each join in the well casing.

- ***Hypothesis 5.2*** that "pipe connection seal materials designed to prevent hydrogen leakage will adequately contain hydrogen gas to facilities piping." This could be tested by testing a variety of pipe sealing materials (e.g., gaskets, glues, or "pipe dopes" of various compositions) and then using leak detectors to measure their ability to prevent leaks during the time span of the test injection.

Other activities occurring under this subtask:

- ***Gas metering***. The total volume of gas injected into and withdrawn from the hydrogen storage test facility will be measured daily.

- ***Well head inspections***. Well heads will be inspected for corrosion, leaks, and evidence of missing or malfunctioning equipment. This will occur daily for the first 14 days of injection, then weekly for the next 10 weeks, then monthly for the remainder of the demonstration. Surveys of any encroaching activities will be included in these inspections.

- ***Isolation Exercises***. Master isolation valve and pipeline isolation valve will be tested every three months. *Standards*: API Standard 6AV2 for valve testing procedures.

- The **Subsurface Engineer** and **Facility Lead** will lead this subtask.

11.2 Reservoir integrity monitoring

Observation well sampling. Fluids and gasses from observation wells will be sampled monthly for evidence of gas migration throughout the reservoir and into other formations and determine if the lateral and vertical extents of the buffer zone around the hydrogen plume have been estimated accurately. This activity will test **Hypothesis 1**: the hydrogen bubble that forms during storage will follow the geometry suggested by simulation studies.

- The **Environmental Scientist**, **Subsurface Geochemist**, and **Facility Lead** will lead this subtask.
- Observations and interpretations on the hydrogen bubble geometry will be included in the final report.

11.3 Gas inventory monitoring

This activity will test ***Hypothesis 2*** that could be tested could be that "the elemental and isotopic chemistry of reservoir water can accurately predict the quantity and composition of hydrogen during production."

This activity will also test ***Hypothesis 3.1 that*** "hydrogen will interact with reservoir fluids similarly to natural gas." This will be tested by measuring the composition of injected and produced gas as well as monitoring reservoir water chemistry during the demonstration injection.

- ***Gas compositional analysis.*** Reservoir gas samples will be analyzed weekly to detect changes in composition of produced gas.
- ***Annual reservoir inventory assessment.*** Annual change in maximum and minimum reservoir pressure and gas inventories will be measured at maximum and minimum hydrogen storage, typically in fall and spring, respectively. Annual pressure hysteresis will be monitored for evidence of gas migration.
- ***Dynamic and static reservoir properties.*** Injection/withdrawal rates, flowing/shut-in pressures, and inventories will be monitored for assessment of integrity.
- The **Subsurface Geochemist** and **Facility Lead** will lead this subtask.
- Observations and interpretations on this subtask will be included in the final report.

11.4 Produced gas analysis and separations

This activity will test ***Hypothesis 3.2*** that "produced hydrogen can be dehydrated using triethylene glycol." This could be tested by passing the produced gas mixture through similar process equipment used for dehydrating natural gas.

- The **Project Staff** and the **Facility Lead** will lead this subtask.

- Observations and interpretations from this subtask will be included in the final report.

11.5 Post-demonstration characterization

After the cessation of injection/production cycling, additional data collection is required to characterize a mechanical or chemical alteration to the well (including wellhead equipment, casing, and cement) or geological formations through which it passes (including caprock, reservoir, baserock, and USDWs).

Petrophysical Well Logging will be performed identify any leaks or corrosion of downhole materials and equipment.

- The **Subsurface Petrophysicist** and **Facility Lead** will lead this subtask.

Tests run in tubing:

- ***Temperature Log.*** Any leak from the well might be expected to change the temperature of the well and its surrounding environment due to the friction of gas escaping through a narrow orifice in the well materials or by increasing biological activity in adjacent rocks. This test would be run above the reservoir. A temperature log showing no anomalous readings would indicate maintenance of well integrity.

- ***Noise Log.*** Leaks from the wellbore would also likely increase acoustic noise that could be measured suing an acoustic sensor. This test would be run above the reservoir. A noise log showing no anomalous noise would indicate maintenance of well integrity.

- ***Pressure testing.*** Inability of the well's open spaces (e.g., within tubing and between tubing and casing) to maintain operating pressures may indicate corrosion of tubing, casing, and or cement. Open spaces will be sealed, and pressure increased to operating levels. Ability of open spaces to maintain pressures would indicate maintenance of well integrity.

- ***Fluid and gas samples*** will be taken from the reservoir identify and characterize any chemical or biological alteration.

- ***Fluid samples from USDWs*** will be collected to identify and characterize any chemical or biological alteration.

Tests to be run with tubing pulled:

- ***Casing Wall Thickness Inspection.*** Changes in casing thickness may indicate corrosion and leaking. A cement wall thickness log will be run for the entire depth of the well. No reduction in casing wall thickness compared to pre-demonstration logging would indicate maintenance of well integrity.

- ***Cement Bond Log.*** Changes in cement bond between casing and geological formation may indicate leaking. A cement bond log will be run for the entire depth of the well. No reduction in cement bond compared to pre-demonstration logging would indicate maintenance of well integrity.

- ***Multi-Arm Caliper Inspection.*** Changes in the internal dimensions of the well may indicate corrosion of the casing and cement and thus areas leaking or prone to leaks. A cement bond log

will be run for the entire depth of the well. No reduction in cement bond compared to pre-demonstration logging would indicate maintenance of well integrity.

- ***Rotary sidewall coring*** will be undertaken to obtain samples of reservoir and caprock material for assessment of mechanical and chemical diagenesis associated with cycling operations.
  - This activity will also test ***Hypothesis 4*** that "hydrogen will have negligible effect on seal or reservoir materials." Collecting rotary sidewall cores at the completion of the demonstration injection and comparing them to core samples taken during well construction to identify any alteration that was caused by the injected hydrogen.

11.6 UHS Field Lab Assessment

Research Question 8 **posited** *Would a field laboratory for UHS be useful?* The project will develop a report assing the usefulness of a field laboratory similar to other DOE-funded field laboratories for geothermal energy production (Utah FORGE) or unconventional oil production with CCUS (Midland and Williston Basins). It may be beneficial to develop a "lab in the field" for UHS in porous media where various construction, production, and monitoring technologies and materials could be tested long term in a field environment. Such a facility could consist of a 5-spot well development with one central injector/producer with four monitoring wells located at various standoff distances.

- The **Project Manager** and **Demonstration Lead** will lead this subtask.

- This subtask will deliver a **UHS Field Lab Assessment Report**.

11.7 Continued regulatory engagement

- The operator of the gas storage test facility will file an application with appropriate regulatory bodies for an amendment to that permit under any of the following circumstances:
  - When a material change in conditions occurs in the operation of the gas storage test facility or in the ability of the facility to operate without causing pollution or the emission of gas
  - Before modifying the area of review of the gas storage test facility
  - Before increasing the gas storage reservoir pressure above the maximum permitted pressure
  - Before adding any additional gas storage test well within the gas storage test facility

- The **Communications Manager** and **Demonstration Lead** will lead this subtask.

11.8 Recordkeeping and reporting

- Monthly reporting for Injection/Withdrawal operations will include:
  - Wellhead (annulus) pressure monitoring
  - Total volume of gas injected into and withdrawn from a gas storage test facility
  - Reports of potential leak
  - Report of any other notable events

- The **Project Manager** will lead this subtask.

12.0 Conclusions

This report provides both an analysis of the major design elements that should go into a demonstration of underground hydrogen storage a porous medium reservoir as well as provides a plan to accomplish such a demonstration in terms of tasks, timing, and personnel.

Design elements include aiming to inject into a sandstone depleted natural gas reservoir that shows a clear four-way closure on seismic surveys.

- ***Using a sandstone reservoir*** because that accounts for a majority of the current fleet of gas storage reservoirs.
- ***Identifying a clear, unfaulted four-way closure*** on 3D seismic surveys will minimize the risk of seal failure.
- ***Using a depleted natural gas reservoir*** reduces the need for purchasing and injecting base gas.
- ***Using a newer facility*** reduces the risk from an older facility with equipment that may be in poorer condition.
- ***Using a reservoir with lower sulfur content*** reduces the risk of negative biogeochemical reactions in the reservoir altering or souring the hydrogen composition
- ***Using a long test cycle (~2 years), lower reservoir pressure (1200 psi), higher deliverability rate (20-100 MCF/day)*** and ***higher storage volume (at least 2 BCF)*** would allow the demonstration findings to be as broadly applicable to current gas storage operations looking to convert to hydrogen storage.

The plan to accomplish this demonstration is designed to accurately characterize the risk in the operation and honestly communicate it to stakeholders. It will collect a broad swath of correlative data on the geology, chemistry, microbiology of the reservoir and caprock system as well as characterize its properties before the demonstration operation begins and after the demonstration ceases. Tasks in the demonstration plan include:

- ***Site description***, where existing data are assembled, analyzed and modeled to identify data gaps.
- ***Risk analysis***, where hazards are identified and assessed as well as preventative and mitigative measures.
- ***Additional data collection***, where any data gaps are filled that reduce uncertainty with regard to geological or other risks.
- ***Reservoir and well design***, where the storage system is engineered.
- ***Site security planning***, where a program for the physical and cyber security of the project site is designed.
- ***Well construction***, where storage and/or monitoring wells are constructed and tested, including analysis of any core material.

- ***UHS Demonstration***, where hydrogen is stored underground, monitored and tested over a length of time, along with post-demonstration analysis and reporting.

At the end of this demonstration, a rich set of operational data and plans will have been produced that will provide useful information to US operators who are be interested in investing in, designing, or developing UHS as well as regulators who may be tasked with assessing the safety of such facilities.

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Contacts

Evan Frye
Natural Gas Decarbonization and Hydrogen Technologies Program Manager
Office of Fossil Energy and Carbon Management (FECM) – Office of Resources Sustainability
U.S. Department of Energy
evan.frye@hq.doe.gov

Timothy Reinhardt
Director – Division of Methane Mitigation Technologies
Office of Fossil Energy and Carbon Management (FECM) – Office of Resources Sustainability
U.S. Department of Energy
timothy.reinhardt@hq.doe.gov

Bill Fincham
Technology Manager
National Energy Technology Laboratory
william.fincham@netl.doe.gov

Angela Goodman
SHASTA Technical Lab Lead, PI
National Energy Technology Laboratory
angela.goodman@netl.doe.gov

Nicolas Huerta
SHASTA Technical Lab Lead, co-PI
Pacific Northwest National Laboratory
nicolas.huerta@pnnl.gov

Joshua White
SHASTA Technical Lab Lead, co-PI
Lawrence Livermore National Laboratory
white230@llnl.gov

Mathew Ingraham
SHASTA Technical Lab Lead, co-PI
Sandia National Laboratories
mdingr@sandia.gov